# Consultant Report FINAL PROJECT REPORT

# ASSESSMENT OF NATURAL GAS COMBINED CYCLE PLANTS FOR CARBON DIOXIDE CAPTURE AND STORAGE IN A GAS-DOMINATED ELECTRICITY MARKET

**Supporting WESTCARB Initiatives** 

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### **PREFACE**

The California Energy Commission Energy Research and Development Division supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The Energy Research and Development Division conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The Energy Research and Development Division strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

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- Renewable Energy Technologies
- Transportation

Assessment of Natural Gas Combined Cycle Plants for Carbon Dioxide Capture and Storage in a Gas-Dominated Electricity Market is the final report for the Carbon Capture and Storage for Natural Gas Combined Cycle Plants project (contract number 500-10-037-01) conducted by CB&I Stone & Webster, Inc. The information from this project contributes to Energy Research and Development Division's Energy-Related Environmental Research Program.

The study began in September 2011 when many CO2 extraction technologies were emerging. After an initial four month data collection period, this study was completed in March 2013 without a site selection for CO2 extraction or plans for a pilot plant. This March 2014 revision encompasses the final assessment by the California Energy Commission and does not include any changes in CO2 extraction technologies.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

### **ABSTRACT**

The newly released California Air Resources Board (CARB) greenhouse gas (GHG) inventory shows natural gas fired power plants to be the state's largest category of point source emissions of carbon dioxide (CO2)1. Under California's mandatory GHG reduction legislation (AB 32), operators of natural gas power plants that emit more than 25,000 metric tons of CO2 per year are required to participate in a multi-sector state-wide cap and trade program. The program has an overall GHG reduction target of 17 percent less than 2013 levels by 2020 and requires an auction price floor for CO2 emission allowances of \$10 per metric ton in 2013, increasing by 5 percent per year plus inflation thereafter. Stakeholders ranging from California's investorowned utilities (IOU) and other power generators as well as the California Public Utilities Commission (CPUC) and California Energy Commission (Energy Commission) are interested in up to date information on the cost and performance impacts of technologies for carbon capture and storage (CCS) at California natural gas combined cycle (NGCC) plants. The U.S. Department of Energy (DOE) is similarly interested in NGCC-CCS options in gas-dominated electricity markets in California and in other states and provided funds for the Energy Commission to conduct an NGCC-CCS engineering-economic assessment and a feasibility study for an NGCC-CCS pilot project in California (the Study).

The scope of this Study is to enhance the information available on CCS to power generation planners and policymakers to aid in their decisions on reducing GHGs from NGCC plants. The following tasks were executed in order to meet the goal of this Study:

- Compile and perform an evaluation of CO2 capture technology options for use on NGCC plants.
- Compare and contrast CO2 capture on other fossil plant technologies to CO2 capture on a NGCC plant.
- Complete an engineering and economic assessment of the installation and operation of CCS technologies, in retrofit and new-build applications.
- Identify considerations for plant design and permitting that are of particular significance for California sites.
- Consider carbon capture system design options that would be beneficial to implementing a CCS to NGCC plants in California.

As noted in studies for other locations, implementing CCS adds a substantial premium to the capital and operating costs of an NGCC plant. Furthermore, there are cost and performance impacts associated with the requirements for dry cooling, which has been common for plants permitted and built in recent years. However, with supportive state regulations and policy measures to encourage CCS technology advancements and optimization for California applications; that support high capacity factors; and provide a means to reduce the financing

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<sup>&</sup>lt;sup>1</sup> http://www.arb.ca.gov/cc/inventory/data/tables/ghg\_inventory\_scopingplan\_00-10\_2013-02-19.pdf



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### **EXECUTIVE SUMMARY**

### Introduction

California's natural gas combined cycle (NGCC) power plants are among the state's largest point sources of carbon dioxide (CO2) emissions and total CO2 emissions for this category are greater than for any other category<sup>2</sup>. Although these plants meet current requirements (per SB 1368)<sup>3</sup> in order to limit the carbon intensity of power delivered to California's regulated utilities, it is likely that NGCC plants will need to implement carbon dioxide capture and storage (CCS) for the state to meet longer term goals under California's mandatory GHG gas reduction legislation (AB 32)<sup>4</sup>.

Stakeholders such as California's investor-owned utilities and other power generators, the California Public Utilities Commission (CPUC), and the California Energy Commission (Energy Commission) have an interest in obtaining comprehensive information on the cost and performance impacts of applying technologies for CCS at California's NGCC plants. With similar interests in advancing the development of NGCC-CCS options for gas-dominated electricity markets in California and in other states, the U.S. Department of Energy (DOE) has provided funds for the Energy Commission to conduct an NGCC-CCS engineering-economic assessment and to develop a proposed scope of work and preliminary feasibility study for an NGCC-CCS pilot project in California (the Study).

### **Project Approach**

The Energy Commission contracted The Shaw Group (now CB&I) to assess the full CCS cycle, including CO2 capture and compression at power plants, rights-of-way acquisition and construction of CO2 pipelines, and CO2 injection well field construction, injection, and monitoring. DOE also provided funding for West Coast Regional Carbon Sequestration Partnership (WESTCARB) researchers at Lawrence Livermore National Laboratory (LLNL)<sup>5</sup> to assess the suitability of subsurface geology to support geological storage of CO2 in the vicinity of California's large NGCC plants.

CB&I's scope of work included conducting an extensive survey of CO2 capture and compressor technology developers, evaluating the performance and cost impacts of applying CO2 capture technologies at representative California NGCC facilities, and developing a life-cycle cost model (Model). Key inputs to the Model include the total capital and operation and maintenance (O&M) costs of the CCS system and performance impacts of CO2 capture and compression process units at representative California NGCC retrofit and new-build sites. The total capital and O&M costs include the CO2 capture and compression system, the CO2 pipeline routing and

<sup>&</sup>lt;sup>2</sup> http://www.arb.ca.gov/cc/inventory/data/tables/ghg inventory scopingplan 00-10 2013-02-19.pdf

<sup>&</sup>lt;sup>3</sup> http://www.energy.ca.gov/emission\_standards/index.html

<sup>4</sup> http://www.arb.ca.gov/cc/ab32/ab32

<sup>&</sup>lt;sup>5</sup> Geologic CO2 Sequestration Potential of 42 California Power Plant Sites, A Status Report to WESTCARB, Lawrence Livermore National Laboratory, June 2011.

associated construction costs in a California Central Valley setting, and the well field drilling, completion, injection, and well integory and subsurface CO2 monitoring costs for a 30+ year injection project.

Most commercial and developmental technologies that are applicable to CO2 capture from fossil power plants use one of three general approaches:

- Post-combustion capture technologies typically remove CO2 from flue gas prior to its discharge from the plant stack.
- Pre-combustion capture technologies remove CO2 from synthesis gas prior to its use to fire a combustion turbine or power boiler.
- Oxy-combustion technologies use high-purity oxygen, typically mixed with recycled flue gas, in the place of combustion air.

CB& I surveyed over 115 suppliers of CO2 capture and compression technologies that vary from emerging technologies to commercial processes mature in other industries. Based on this review, CB&I concluded that a likely nearer-term application for California design conditions could be best represented by a post-combustion capture system, with dry cooling technologies used for heat rejection from the capture and compression processes. Representative performance and cost characteristics were incorporated in the Model developed to evaluate the primary study cases for retrofit and new build applications. Evaluations were also performed for alternative configurations employing flue gas recirculation (FGR) and wet or hybrid wet-dry cooling systems for the CO2 capture and compression process units.

CB&I selected one existing plant and one proposed new-build plant, developed performance and cost information for the Model (using site characteristics along with generic design details), and performed site-specific engineering assessments of the performance and cost impacts associated with CCS. The CB&I Model was used to estimate the life-cycle levelized cost of production (COP) and cost of CO2 avoided (\$/ton) for the specified design conditions. Sensitivity analyses examined the effect of variations in key economic assumptions.

### Key Findings and Conclusions

CO2 Capture Technology

It is expected that post-combustion capture would be the easiest approach to integrate with most existing NGCC plants. Although post-combustion CO2 capture cannot be considered proven at utility power plant scale, some capture processes have been demonstrated at large pilot or pre-commercial scale facilities and suppliers claim it is ready for full-scale application at NGCC power plants.

However, special consideration must be given to the conditions at many California locations such as high summer ambient temperatures and the limited availability of water. In addition, there is the requirement for dry cooling for plants built in California. The Study found that the capture effectiveness and parasitic power consumption of the CO2 capture equipment is a significant function of ambient air temperature and cooling water availability. The requirement

for dry cooling, which is common for new NGCC plants built in California, leads to the use of expensive CO2 capture system cooling water refrigeration when attempting to reach a typical design criterion of 90 percent CO2 capture on all but the hottest summer days. An initial evaluation assumed that the capture system cooling water would be chilled in order to maintain absorption process in the temperature range required to attain a 90 percent capture rate on a hot summer day. For an NGCC plant using air cooling for chiller heat rejection, there are substantial increases in net heat rate, levelized COP, and cost of CO2 avoided. To avoid this impact the Model was revised to achieve 90 percent capture at an annual average ambient temperature design point. The Study found that for a dry-cooled system, substantial savings resulted from relaxing the capture effectiveness criterion to 90 percent CO2 capture on an average day rather than on a hot summer day. Although such a capture system would then remove less than 90% of the CO2 on hot days, this would be acceptable with a flexible regulatory structure and be suitable for applications where the captured CO2 was being used for other beneficial uses such as EOR. In situations where modest amounts of cooling water were available, such as reclaimed wastewater treatment plant effluent, or other gray water, the CO2 capture process unit would have its best performance and lowest cost.

The Study also examined recirculation of a portion of the flue gas back to the combustion turbine (CT) inlet FGR to both increase the CO2 concentration and reduce the flue gas treatment flow. Findings suggested this approach could yield savings in the CO2 capture system capital costs and energy requirements.

Alternative "pre-combustion" approaches to CO2 capture were also reviewed in the Study. These are akin to technologies employed in the chemical processing industry for the production of plastics or hydrogen from natural gas. Relative to post-combustion approaches, there are fewer technology developers and successful application typically involves modification to CTs in the base NGCC plant. In particular, the fuel composition is shifted to predominantly hydrogen rather than methane. Although some CT manufacturers have made progress with hydrogen combustors, it appears further research, development, and demonstration (RD&D) is needed to commercialize a CT that operates efficiently and reliably on hydrogen fuel.

Fuel combustion in high-purity oxygen, rather than air (which is 78 percent nitrogen and 21 percent oxygen), is used in some novel combined cycle technologies. Academic studies and combustor-level bench testing have been performed for "conventional" NGCC oxy-combustion approaches, which dilute combustion air with recycled flue gas. Another "oxy-combustion" approach uses chemical looping with oxygen. These approaches reduce the volume of combustion gases that must be treated for CO2 separation. Given their unique nature, oxy-combustion processes are more difficult to model for evaluating cost and performance impacts in the manner used by the Study for post-combustion capture, although such evaluations are usually available from the technology developers. Oxy-combustion appears to offer future promise if unique equipment can be successfully and economically scaled up and if the high cost and auxiliary power requirements of oxygen production can be addressed. Considerable development efforts are under way, particularly for units at the small end of utility scale that could be sited in or near oilfields where the separated CO2 can be used for enhanced oil recovery (EOR) operations.

### CO2 Pipeline Transportation and CO2 Storage

The technical and regulatory issues associated with CO2 pipeline transport and CO2 injection and monitoring, often cited as a significant unknowns, appear to be relatively minor components of the overall cost of CCS for the NGCC sites evaluated in the Study. The Study concludes that pipeline costs are relatively predictable, at least for flat rural settings, because CO2 pipelines have been used for over 40 years in EOR operations and there are over 4,000 miles of such pipelines in the United States.

Although California does not currently have a formal framework to address CO2 pipeline permitting, design, and operation, the issues of CO2 pipeline safety are within the jurisdiction of the State Fire Marshal. There remains an opportunity for policymakers to draft appropriate statutes or regulations to assure safety and optimized routing, as well as authorizing the use of eminent domain for CO2 pipeline right of way acquisition, where needed.

The availability of geologic reservoirs with sufficient CO2 storage capacity and the cost of construction and O&M of CO2 injection and monitoring wells appear not to pose significant barriers to CCS for most California NGCC plants. Nonetheless, there are some regulatory, permitting, and legal uncertainties that could slow the development of CO2 storage sites. These include acquisition of pore space use rights for CO2 storage, particularly when spanning a significant number of landowner parcels; permitting of Underground Injection Control (UIC) Class VI CO2 injection wells, particularly for wells initially permitted as UIC Class II for EOR operations; and long-term liability for injected CO2 that might migrate from its storage zone.

Still, the estimated engineering, procurement, and construction (EPC) costs for the CO2 transportation and injection systems, under both the Study's NGCC retrofit and new build scenarios, were less than 5 percent of the total EPC costs for the CCS system.

### CCS Performance and Cost Impacts

The Study estimated that the impact of retrofitting CCS to a reference NGCC plant in California<sup>6</sup> would be about a 15 percent reduction in the "net" generating capability (i.e., power delivered to the grid) because some of the steam and electricity produced by the base NGCC plant is used by the CO2 capture and compression process units. The net capacity reduction for a comparable new-build NGCC facility would be less, about 11 percent, because of greater opportunities to optimize the integration of the CO2 capture and compression systems into the plant design. Similarly, the use of steam and power in the process of capturing and compressing CO2 reduces the overall net efficiency of an NGCC power plant with CCS. Measured as an increase in net heat rate, this impact is about 17 percent for the retrofit case and about 12 percent for the new-build case.

The Study estimated that the total EPC cost for installing CCS at a new build, nominal 600 megawatt (MW) NGCC plant in California is about \$900 million. The total EPC cost includes

<sup>&</sup>lt;sup>6</sup> These analyses were based on typical "F" class combustion turbines in a 2x2x1 configuration.

the CO2 capture and compression systems as well as the CO2 pipeline and injection systems<sup>7</sup>. This cost is higher than the costs at other typical U.S. locations due to the requirement for dry cooling of the power plant and CO2 capture and compression process units, higher labor costs, and use of an EPC contracting structure instead of an engineering, procurement, construction management (EPCM) contracting structure. The latter monetizes more of the risk in the cost estimate, which CB&I believes is a more realistic approach. The levelized COP for the new build NGCC facility was estimated to increase by approximately 35 percent due to the addition of the CCS system.

Activities which may reduce capital costs in the future include focused technology RD&D and a growing EPC knowledge base. A reduction in future capital costs by 30 percent would result in a levelized COP decrease of approximately 25 percent. Reductions in financing costs, for example through government loan guarantees, could further reduce the COP.

### Next Steps

What next steps are needed to apply CCS to NGCC plants in California? The next steps range from technology developments, optimization studies, pilot facilities to private/public investments. Listed below is what we consider particularly beneficial to the California NGCC-CCS application.

- CO2 absorption solvents and advanced capture technologies that improve the functionality of CO2 capture systems at high ambient temperatures without undue cooling requirements
- Optimization studies utilizing CO2 capture process simulation models in conjunction
  with technical-economic assessments of alternative cooling approaches for CO2 capture
  and compression systems incorporating the unique aspects of California NGCC sites
  and a goal of minimizing water use.
- Private/public investment in a pilot project to evaluate CO2 capture technologies tailored specifically to California design conditions. The pilot facility could also test technology improvements such as FGR and high temperature solvents. Examples of pilot projects include: (a) NGCC-CCS large pilot tests at the Technology Centre Mongstad (TCM) in Norway, commissioned in May 2012, which will test flue gas from a natural gas combined heat and power facility and (b) the proposed Peterhead project in Aberdeenshire, Scotland involves full scale application of CCS on an existing NGCC facility. Elements of a draft "charter" for a potential pilot plant project are discussed in Chapter 3.
- CT developments designed specifically for oxy-fuel combustion and pre-combustion CO2 capture systems.

<sup>7</sup> EPC costs do not include Owner's costs, interest during construction, inflation and escalation, and project contingency.

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In the current market and regulatory environment, the projected life-cycle costs for an NGCC plant with CCS will exceed the current cost of a conventional NGCC plant with the purchase of CO2 emission allowances from the California cap-and-trade market. However, allowance prices are expected toincrease over time and CCS technology RD&D requires a significant lead-time. Thus, it is in the public interest for early CCS projects in California, to expand the portfolio of economic greenhouse gas (GHG) reduction options. There are incentives and regulatory accommodations that could improve the economics of early CCS projects as listed below:

- Collaborative funding for CCS RD&D from a combination of stakeholders (e.g., state and federal government, private industry, shareholders, and ratepayers)
- Incentive programs similar to those proposed in federal climate change bills (including cash payments per ton of CO2 sequestered and possibly direct funding)
- Tax incentives for sequestering anthropogenic sources of CO2 for EOR (e.g., policy in Texas), and must-run designation for CCS-equipped NGCC units in power markets
- Capital cost subsidies including federal (e.g., DOE cost share grants), and state subsidies (potentially through cap-and-trade auction proceeds or an electric utility surcharge across all utilities and ratepayers), or loan guarantees (similar to DOE loan guarantees)
- Formal recognition of CO2 sequestered by CCS projects in the cap-and-trade program
- Prizes such as the President's upcoming Fiscal Year 2014 budget request that would establish a new \$25 million prize for the first NGCC plant to integrate CCS technology

# CHAPTER 1:

# Summary of Overall Assessment of California Ngcc Plants and Co2 Capture and Compression Technologies

At the initiation of the Study, CB&I reviewed, updated and expanded on a preliminary assessment paper prepared by the West Coast Regional Carbon Sequestration Partnership (WESTCARB)<sup>8</sup>. The WESTCARB assessment paper provided:

- Listing of approximately 24 known CO2 extraction and capture technologies.
- Characteristics of the planned or under construction NGCC sites in California.
- Characteristics of the operating NGCC sites in California.
- Emissions data associated with the operating NGCC sites in California.
- Locations of the NGCC plants and potential CO2 storage sites.

CB&I identified the Project Tasks, which would address the key components in the WESTCARB assessment including; space availability for retrofit equipment, CO2 storage geology, CO2 transport pipeline routing, equipment and configuration commonality, economic viability, and cooling technology.

CB&I reviewed the WESTCARB list of existing and planned NGCC sites in California and determined that a majority of the sites utilized an arrangement of two F-class CTs, two heat recovery steam generators (HRSGs) and one steam turbine (ST) ( $2 \times 2 \times 1$ ). Although there are several other arrangements represented on the WESTCARB list, the  $2 \times 2 \times 1$  configuration was selected as the basis for the Study to provide consistency.

Figure 1 illustrates the location of the selected 2 x 2 x 1 NGCC sites in California that were considered for site-specific evaluations of CO2 capture and injection operations in the Study. CB&I also developed individual site maps for candidate NGCC sites that included potential CO2 injection sites (i.e., saline aquifers or potential enhanced oil or gas recovery sites) and other notable features such as fault lines and river locations.

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<sup>&</sup>lt;sup>8</sup> Assessment of Natural Gas Combined Cycle Plants (NGCC) for Carbon Dioxide Capture and Storage in Gas-Dominated Electricity Market – Request for Proposals (RFP# 500-10-502).

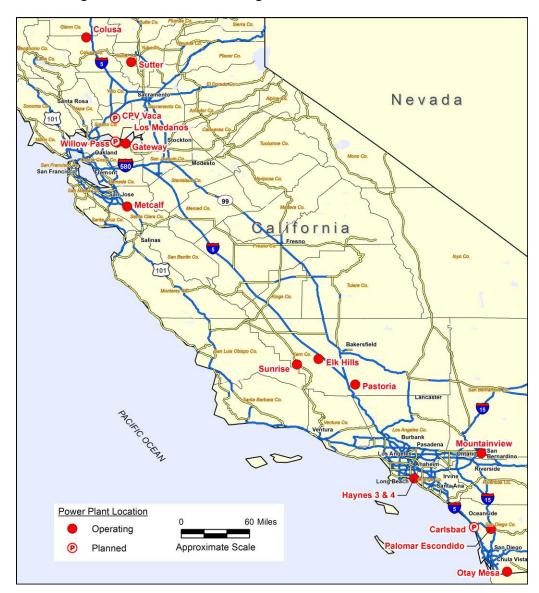


Figure 1: Locations of Existing and Planned 2x2x1 NGCC Plants

Source: CB&I

The economic viability of CCS at NGCC facilities is affected by projected future capacity factors as well as the remaining life of the NGCC facilities. Table 1 presents a summary of historical capacity factors and estimated remaining useful life of candidate NGCC sites in California.

Table 1: Summary of Historical Capacity Factors for 2x2x1 NGCC Plants

Plant	Year Online	Historical Capacity Factor	Remaining Useful Life <sup>1</sup>
Colusa 2010/11 Not Available.		29	
Gateway	Gateway 2009 CF >50% in startup year 2009.		27
Elk Hills	2003	CF ~66-71% for 2005, 2008, 2009.	21
Haynes	2005	CF >60% avg for 2008-09.	23
Los Medanos	2001	CF ~59-65% for 2005, 2008, 2009; fractional cogen supply to USS-Posco.	19
Metcalf	2005	CF~36% in startup year 2005; ~64% in 2008; ~56% in 2009.	23
Mountainview	2005	CF ~73% in 2008; ~62% in 2009.	23
Otay Mesa	2009	~15% CF in startup year 2009.	27
Palomar	2006	CF ~73% in 2008; ~67% in 2009.	24
Pastoria	2005	CF~39% in 2005; ~74% in 2008; ~75% in 2009.	23
Sunrise	2003	CF ~72% in 2008-09.	21
Sutter	2001	2 years w CF <50%; avg >50%.	19

Note - <sup>1</sup>Fossil power plants have been traditionally designed for an expected useful life of 25-30 years. However, industry experience has shown that fossil power plants can be operated safely for 40 years and beyond with proper maintenance and inspections. However, for purposes of this study we assumed a useful life of 30 years.

Source: Quarterly Fuel and Energy Report (QFER) CEC-1304 Power Plant Owner Reporting Database

CB&I developed assumptions, for the Energy Commission approval, that were used in the market simulation modeling performed in the Study to develop projections of future capacity factors at the candidate NGCC sites in California. These capacity factor projections include the impacts on dispatch of increased operating costs due to CCS as well as projected market prices of CO2 allowances.

### 1.1 Overview of CO2 Capture Technologies

CB&I conducted an assessment of CO2 capture technologies that could be applied to California NGCC power plants. This assessment considered basic measures of expected performance and

cost, developmental status, and technology-specific design considerations for various CO2 capture technologies and resulted in recommendations of CO2 capture technologies to evaluate in the Study.

CB&I considered CO2 capture technologies ranging in maturity level from emerging to more developed processes and covered the following CO2 capture technology categories9:

- Pre-Combustion
- Post Combustion
- Oxy Fuel
- Other Methods or Concepts

Pre-Combustion Capture is a technique where the CO2 is captured before burning the fuel in a combustor. It is commercially available for several applications, including hydrogen, ammonia, and synthetic gas production. The technique consists of a natural gas reforming or coal gasification step followed by water gas shift reforming of the gas, with subsequent steps for separation of CO2 and H2 to produce a H2-rich gas. The main challenge within this concept to make it economically feasible is to develop CTs that reliably can burn fuel with a high H2 content. Because of the world-wide interest in the hydrogen economy, a lot of research and development (R&D) efforts are currently put into this field.

In Post-Combustion Capture, the CO2 is removed from the power plant flue gas. The state-of-the-art technique for separating CO2 from flue gases is through chemical solvent scrubbing (usually with an amine). The CO2 reacts with the amine in the absorber and is later separated from the amine solution in the stripper, then dried, compressed, and transported to the storage site. For flue gases with a low partial pressure, a large amount of energy is needed to regenerate the solvent. Improved solvents and optimized processes are currently being developed. Alternative methods for separating CO2 from flue gases are also evolving.

In Oxy-fuel Carbon Capture (also called denitrogenation), the fuel is combusted using almost pure oxygen at near stoichiometric conditions. This creates a flue gas consisting of mainly CO2 and H2O. A portion of the CO2 in the flue gas is recycled in order to control the combustion temperature. Oxy-fuel combustion has been used within the metal and glass manufacturing industries for some time, but has so far not been applied to full-scale conventional steam boilers. The main challenges with this concept are the new combustion environment in the burner, and the high energy demand of the air separation unit (ASU).

### 1.2 Overview of CO2 Compression Technologies

Captured CO2 must be dried and compressed before it is delivered to a transport pipeline or injected for permanent storage in a geological formation. CB&I surveyed several vendors and

<sup>&</sup>lt;sup>9</sup> As defined in DET NORSKE VERITAS, DNV-RP-J201, Qualification Procedures for CO2 Capture Technology.

developers of CO2 compression technologies to determine the technical attributes of the compression system associated with the pressurization and dehydration required for transporting CO2 to the well head(s) and increasing pressures to inject CO2 into the ground at either new or existing locations. This information was used to develop a reference compression system that could be modified in later stages of the Study to address site-specific considerations of CO2 capture, transportation and injection.

Initial sequestration investigations using data from the Lawrence Livermore National Laboratory (LLNL) indicated a need to plan for compression at the injection well(s). Preliminary indications were that the injection pressures would exceed the transport pressure required to maintain constant flow. Initial performance requirements for the CO2 compressors were established and an initial data sheet and requests for information (RFI) was prepared.

CB&I submitted a data sheet and RFIs to major suppliers of compression equipment. The list of suppliers was developed based on CB&I's experience with a CO2 capture study conducted for the North Dakota Lignite Energy Council, known CO2 compression and transport capabilities, WESTCARB affiliations, and a general industry understanding of problems associated with large transport systems, both in terms of flow rate and pipeline length. In addition to selecting suppliers experienced in designing well-head systems, CB&I selected a shockwave compression technology supplier involved in DOE research in this area.

### 1.3 Evaluation of CO2 Capture Technologies

CB&I contacted over 115 developers and suppliers of CO2 capture technologies in an effort to survey a wide range of potential CO2 capture concepts for NGCC power plants. The level of detail provided by respondents varied from minimal to highly detailed, however respondents that provided highly detailed performance analyses generally requested that CB&I not publish that information and use it for background only. Few respondents were willing to provide significant detail about technology costs. CB&I also performed web searches of literature and was available to fill some information gaps with publicly available references.

CB&I used the survey results to develop a general assessment of the relative maturity of different categories of CO2 capture technology, to identify technology-specific design considerations, and to develop background information to use in estimating relative expected performance and potential costs for the CO2 capture technologies or concepts.

From its assessment of the survey responses, CB&I concluded that only solvent-based post-combustion capture technologies were currently at a level of maturity that was likely to support retrofit or new-build demonstration projects, at commercial scale, in the time frame envisioned for this Study. Technologies that require significant changes in the design of the major equipment such as CTs, STs and HRSGs would not likely be considered for new projects where such major equipment has been ordered and is in the design and manufacturing cycle.

• For deployment of NGCC units with pre-combustion capture, an experience base exists with commercial applications of the individual components. However, several studies

to date indicate that implementation of NGCC with pre-combustion capture is likely to have less favorable economics than an NGCC with post-combustion capture.

- Literature surveys revealed academic studies and combustor-level development for "conventional" oxy-combustion NGCC technology, using the synthetic air approach with flue gas recycle. No concrete plans for full integration with a CT or NGCC were identified.
- Several technology developers have achieved pilot-scale demonstrations of innovative NGCC concepts incorporating oxy-combustion and continue to make steady progress toward commercialization. These concepts incorporate major revisions to the NGCC flow sheet and would only be applicable for a new-build. At this point in time, available cost and performance information is insufficient to complete an engineering-economic evaluation at the level desired for this Study.

Researchers have identified many concepts for post-combustion capture technologies that are potentially capable of treating the flue gas from an existing NGCC power plant without requiring significant modifications to the existing major equipment such as CTs, STs and HRSGs. The technologies in this category range in maturity from early computer models and bench scale proofs-of-concept to proven technologies that are technically feasible, although not currently economical, for application at power plant scale. Key parameters that CB&I considered in selecting the best technologies to consider for the Study model include the following:

- 1) Level of development and commercial maturity.
- 2) Prospects for being at utility power plant scale by 2020.
- 3) Development of nominally one MW equivalent scale by March 2011.
- 4) Degree of documentation provided or available to support development of more detailed Study models for evaluating NGCC-CCS application at selected sites.
- 5) Operating principles and approach of the CO2 capture technology.
- 6) Source and quality of expected performance and costs information.
- 7) Relative impacts on utility scale NGCC (technical or economic).

# 1.3.1 Selection and Assessment of CO2 Capture Technologies for Use in Study Models

In most post-combustion capture systems, CO2 is removed from the power plant flue gas after it has passed through the HRSG. Typically, the relatively cool CO2 reacts with a solvent in the absorber and is later separated from the solvent solution in the relatively hot stripper, then dried, compressed, and transported to the storage site. The CO2 loading of the "rich" solvent is lower for flue gases with a low CO2 partial pressure. A larger ratio of solvent to flue gas is therefore required and, a larger amount of energy is needed to strip CO2 from the solvent (i.e., regenerate the rich solvent to lean solvent). Development efforts are aimed to identify

improved solvents and optimize processes that achieve higher CO2 loading and require less energy for solvent regeneration. Other efforts are aimed at developing alternative methods that reduce the costs and energy requirements for separating CO2 from flue gases.

As the responses provided by the technology suppliers were not sufficient in themselves to develop detailed technical assessments, CB&I developed three composite specifications for post combustion CO2 capture technologies that would be subjected to evaluation. Study Case A, selected as the nominal (reference) case, used data for the monoethanol amine (MEA) process detailed in the National Energy Technology Lab (NETL) report Cost and Performance Baseline for Fossil Energy Plants<sup>10</sup>. Study Case B examined a synthesized technology specification that included composited performance characteristics of several state-of-the-art solvent technologies. Study Case C used composited performance characteristics for a developmental process that could potentially have lower cost of CO2 avoided than technologies that are currently near commercial maturity. Table 2 shows the electric power, steam and cooling requirements for Cases A, B and C. Values are based on a Reference Plant power island that consists of a nominal 555 MW, 2 x 1, F-class NGCC plant currently in design. This Reference Plant served as the power island for performance evaluations and plot space analyses.

The technology supplier responses did not include detailed heat balances, as these were considered proprietary. However, the responses did, in combination, allow preliminary determination of electric loads, cycle power losses, and cooling tower makeup water requirements for Cases A, B, and C, which are summarized in Table 2. As indicated in Table 2, newer post combustion CO2 capture processes have less effect on the output and efficiency of the power plant.

Table 2: Preliminary Comparison of Electric Loads, Cycle Power Losses and Makeup Water Requirements

	Case A	Case B	Case C
Electric Load (MW)	26.7	37.4	36.5
Cycle Power Loss (MW)	92.6	70.4	62.5
Total CCS Power Loss (MW)	119.3	107.8	99.0
Total CCS Power Loss (% of Gross Output)	22.1%	19.9%	18.3%
Cooling Tower Makeup Water (gpm)	2,245	2,010	1,249

Source: CB&I

 $^{\rm 10}$  "Cost and Performance Baseline for Fossil Energy Plants", NETL, October 1, 2010

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### 1.3.2 Increase in Plant Water and Waste Water

The changes in water consumption and waste water production for retrofit of CO<sub>2</sub> capture technology to an existing NGCC generating plant were estimated by developing preliminary water balances based on the Case B data since it was the most complete. While the relative quantities for the other cases may vary somewhat, the variations were not considered to be significant due to the similarity of the processes. The initial water balances assumed the use of cooling towers as a "worst-case" indicator of potential increases in plant water consumption and wastewater discharges.

### 1.3.3 Impact of CCS on Plant Operating Flexibility and CT Operations

The primary factors affecting plant operating flexibility are:

- Startup time HRSG drum heat up rate and ST heat up rate.
- Load ramp rate ST temperature differentials.
- Turndown CT minimum load.

CB&I examined limiting factors for startup time, load ramp rate, and turndown for NGCC facilities without CO2 capture technology and whether post-combustion CO2 capture technology operations would adversely affect these parameters. It was concluded that parameters would not be affected by the post-combustion CO2 technology operations. Since the post combustion technologies selected do not have a significant effect on CT operation (the CCS booster fan(s) will compensate for any additional exhaust pressure drop) impacts were not evaluated.

### 1.3.4 Health and Safety

The impact of full scale CO2 capture technologies on flue gas stack emissions of criteria pollutants and hazardous air pollutants (HAPs) is not widely known. However, these impacts are not considered to be a fundamental limiting factor in the development or application of CCS technology to NGCC power plants. Further evaluation of this issue would be a beneficial component of future pilot scale testing.

Amines are a family of chemicals that show great promise for use as a solvent in post combustion CO2 technologies. They are used in varied forms for this purpose and will continue to evolve as post combustion carbon capture technology continues to develop. Many of the solvents used in post combustion CO2 capture technologies do not have readily available material safety data sheets because of proprietary information in their formulation. However, the chemical compound that is generally referred to in their formulation, MEA, is a common industrial product. MEA is a toxic, flammable, corrosive, colorless, viscous liquid with an odor similar to ammonia. Due to characteristics common among CO2 capture solvents and other products typically used at NGCC sites, major changes in the operations, safety preparedness measures, environmental control/assurance, or material handling and disposal procedures are not expected at NGCC sites.

A report prepared by The Bellona Foundation<sup>11</sup> (Bellona Report) acknowledges that some amines and amines degradation products can have negative effects on human health and the environment. MEA itself will not have adverse effect to human health and the environment. However, once emitted to the air, the amines will start to degrade to other products some of which will not have negative environmental effects but others will have adverse environmental impacts such as nitrosamines, which are carcinogenic. Although there are concerns regarding atmospheric degradation of amines and the risk to human health; research and development recommendations described in the Bellona Report indicate that these risks are manageable and do not give rise to limiting the use of amines in CCS deployment.

The Bellona Report recommends concerted efforts to understand knowledge gaps and proper risk management strategies for the safe use of amine compounds in post combustion CCS systems. The executive summary of the Bellona Report concludes by saying "The knowledge gaps on environmental impacts from amines are therefore not expected to delay the commercialization of CCS."

### 1.3.5 Economics

None of the individual CO2 capture technology supplier responses provided sufficient detail for a detailed quantitative evaluation of the individual process for the Study. The unrefined stream of CO2 from a typical post combustion capture process has a potential market value for use in EOR. EOR utilizes CO2 by injecting it in depleted oil fields to increase production. Using CO2 for EOR can also serve the function of geologically sequestering the CO2 because the injected CO2 is retained in the subsurface formation after oil production ends and wells are plugged.

Since oil companies are willing to pay for and take ownership of CO2 generated by power plants to use in EOR, the power plant operator can not only avoid the liability and costs associated with CO2 disposal, but also receive an additional source of revenue. The higher the oil price, the more valuable the additional oil production; therefore, the CO2 sales price is typically indexed to the price of oil. California has several regions with oil fields that may have the potential for EOR with CO2, notably in Kern County and the Sacramento Valley in the Central Valley as well as Ventura County and Los Angeles County in Southern California.

At the level of this Study, the financial benefits of selling the CO2 for EOR is not included in the base case economic analysis. To test the impact of selling CO2 for EOR on the COP, sensitivity analyses that considered various CO2 sales prices were performed.

### 1.4 Regulatory and Permitting Issues

CB&I identified the regulatory and permitting issues and requirements that may be encountered in the implementation of CO2 capture technologies, CO2 transportation and long-term storage of CO2.

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<sup>&</sup>lt;sup>11</sup> Bellona Foundation, Amines Used in CO2 Capture – Health and Environmental Impacts, Shao and Stangeland, September, 2009.

### 1.4.1 California Carbon Capture and Storage Review Panel

The California Public Utilities Commission (CPUC), the Energy Commission, and the California Air Resources Board (CARB) established a CCS Review Panel (Panel) in February 2010, in recognition of the importance of CCS for California's industrial and electricity sectors. The Panel was composed of experts from industry, trade groups, academia, and environmental organizations. The Panel held five public meetings to arrive at its findings and recommendations. These meetings were designed to solicit input from technical experts and key stakeholders and to allow the Panel to deliberate in an open, public setting.

The Panel identified a number of key legal and regulatory issues that require greater clarity and possible legislative action before CCS can be broadly deployed as a GHG mitigation measure under state laws and policies to reduce CO2 emissions. Key questions identified by the Panel included:

- 1. Will CCS be eligible to meet the requirements of AB 32 or other relevant California laws and policies?
- 2. Is there a clear regulatory framework and related permitting pathway for CCS projects in California?
- 3. Are there clear agency rules that would allow for early CCS demonstration projects in the State?
- 4. What additional considerations must be addressed and resolved to allow for the deployment of CCS?

The Panel deliberated on the key issues listed above and put forth key findings and recommendations for consideration by the three principal agencies that created the Panel as well as the state legislature.

### 1.4.2 Permitting Overview for Power Plant CCS Projects in California

The permitting process for industrial development projects in California involves a multitude of federal, state, regional, and local agencies, each with its own authorities and regulatory requirements. The lead agency for the environmental documents required under the California Environmental Quality Act (CEQA) coordinates its review of an Environmental Impact Report (EIR) or Negative Declaration (ND) with the other responsible permitting agencies.

The Energy Commission serves as the lead agency under CEQA for the permitting of power plants, with 50 MW or greater net output. For projects below 50 MW net output, a city, county, or regional body will typically be the lead agency. The Energy Commission's license and certification process subsumes the requirements of state, local, or regional agencies otherwise required before a new plant is constructed. The Energy Commission coordinates its review of the facility with other permitting agencies to ensure consistency between their requirements and its own conditions of certification (COC). Current understanding is that the Energy Commission retains this role for new plants with CCS and for permit revisions for plants that are to be retrofitted with CCS technology.

A background report for the Panel summarized and evaluated options for establishing a regulatory framework for CCS projects in California. This report concluded that any legal or regulatory framework that is established for permitting CCS projects should be clear and transparent, providing needed guidance to project developers on specific regulatory requirements. In addition, the framework should balance regulatory certainty with the need to protect public health and the environment. The report identified regulatory gaps, which exist in California for CCS projects, especially CCS projects that do not involve EOR. Three regulatory gaps that were identified include the identification of: 1) "primacy" over CCS injection wells, 2) state authority to regulate CO2 pipelines, and 3) Monitoring, Measurement, and Verification requirements for geologic carbon sequestration.

### 1.4.2.1 Permitting CO2 Capture and Compressor Retrofits

The retrofit of CO2 capture and compression technologies at a particular power plant may require modifications to existing permits or plans and reports and possibly new permits or plans and reports for compliance with the applicable laws, ordinances, regulations & standards (LOR&S). Early in the permitting process for a CCS project, an applicability review of existing plans, reports and LOR&S would be performed to guide the overall permitting process for the CCS project.

The need for new or modified permits, plans, and reports at an existing NGCC facility will be impacted by both the design of the existing facility as well as the detailed design of the retrofit CO2 capture technology. Existing facility designs can impact the ability to integrate the mass and energy balance requirements of the selected CO2 capture technology into the existing plant systems. New process equipment may be needed to eliminate or minimize new discharges due to the CO2 capture technology.

Preliminary estimates of changes in facility wastewater discharges, air emissions, heat rejection, water requirements, delivery and storage of new materials, equipment layouts, equipment noise levels, and storage and disposal of new solid and liquid waste streams are typically prepared prior to developing an environmental permitting plan.

The major environmental permits and plans, which could be impacted by the retrofit of CO2 capture technologies at a NGCC facility include the air permits (Authority to Construct and Permit to Operate), Approval of Water Rights, and National Pollutant Discharge Elimination System (NPDES) wastewater discharge permit. It is expected that there would be modifications to a number of plans and reports held by the facility to account for the additional equipment added to the site and the receipt and storage of new chemicals associated with the CO2 capture system. The CCS project would also result in new COC issued by the Energy Commission.

CB&I does not anticipate that required modification of existing permits, plans and reports at existing NGCC facilities due to the retrofit of the CO2 capture technology, will present a significant barrier to developing successful CCS projects.

### 1.4.3 CO2 Transportation Issues

### 1.4.3.1 Pipeline Siting and Safety

If the power plant does not overlie a suitable geologic reservoir, the CO2 will be transported by way of a pipeline. There are human health and environment risks, which need to be considered with CO2 transport to a geologic storage reservoir. The adverse effects from a potential leak of concentrated CO2 from a pipeline must be prevented by enacting policies to manage and mitigate risk, ensure proper monitoring and safety measures, and through proper design and planning.

The issues associated with CO2 compression and pipeline transport are well understood because CO2 has been used for over 40 years in EOR operations. Currently there are over 4,000 miles of CO2 pipeline in the United States; virtually all of which is used to supply CO2 for EOR. CO2 transported by pipeline differs from many other pipeline systems such as natural gas in that the CO2 product is conveyed at very high pressures (approximately 2,000 psi) compared to natural gas (transported at pressures of up to 1500 psi). Pipelines transport CO2 under high pressure as a supercritical liquid that results in high volume transport with minimal pipe diameter.

The Federal Pipeline Safety Reauthorization Act of 1988 included a provision for the regulation of CO2 pipelines. Regulations are promulgated under the U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA defines CO2 as a fluid consisting of more than 90 percent CO2 molecules compressed to a supercritical state. Although PHMSA does not define CO2 as a hazardous liquid it is regulated as a hazardous liquid. The PHMSA regulations address design, construction, operation and maintenance, corrosion control, and reporting requirements. These Federal Regulations govern interstate transport of CO2. DOT has retained the regulations governing CO2 pipelines "for administrative convenience" largely in part to see that they are properly regulated amidst the much larger volume of natural and hazardous liquid pipeline systems.

The CPUC does not currently have a regulatory framework in place to address CO2 pipeline design and operation. Consequently, this presents a challenge as well as an opportunity to policymakers to draft appropriate regulations that meet or exceed current federal standards. However, the state has the opportunity to develop these regulations from a clean slate and can address the unique situation of transporting CO2 to a reservoir for geologic storage or for EOR.

The State Fire Marshal has safety and enforcement authority over intrastate hazardous liquid pipelines under the Elder California Pipeline Safety Act. However, California does not have a statute that addresses the siting of CO2 pipelines on state or private land.

Because the CO2 within a pipeline is at very high pressures, a sudden pipeline failure could lead to a high velocity release of gases. The dense nature of CO2 also presents a hazard as a release of this gas in a highly populated area could represent a significant safety hazard because it will displace oxygen. A sudden failure event and failure modes should be taken into account as part of a risk analysis in the design, construction, operating, and monitoring of a CO2 pipeline.

### 1.4.3.2 CO2 Pipeline Eminent Domain Authority

The development of CO2 pipelines for EOR or geologic storage could be impractical, if not impossible, to site without the power of eminent domain. California does not have a statute specifically authorizing the use of eminent domain for CO2 pipelines. Although public utilities in California can exercise the power of eminent domain in certain circumstances, other entities that could sequester CO2, lack that ability, which could hinder the broader implementation of carbon sequestration.

The Panel concluded that CCS-related site access rights could be legislatively addressed through a relatively small change to the language in existing statutes that provide authority for natural gas storage. The legislative action would be to amend the current language to include CCS. The authority in existing California law for underground natural gas storage condemnation is with the CPUC. A few extra steps would be needed to include such language in the statutory authority of the Energy Commission.

The Panel's technical advisory committee prepared a white paper titled "Establishing Eminent Domain Authority for Carbon Storage in California." This white paper provides sample amendments that would extend condemnation authority to carbon sequestration facility operators following the natural gas storage model. The Review Panel concluded that there are pros and cons to legislative action in this area, and such legislation should be approached with caution due to the public interests and sensitivities. However, legislation authorizing the use of eminent domain for CO2 pipelines would likely further the implementation of carbon sequestration to the extent it does not lead to opposition against projects.

### 1.4.4 CO2 Long-Term Storage Issues

### 1.4.4.1 Siting of CO2 Storage Reservoirs

The CPUC regulates underground natural gas storage. The Legislature could give statutory authority to the Energy Commission for the regulation of CO2 storage. These regulations would ensure both the safety of CO2 storage operations and the permanence of CO2 within the reservoir, which would include standards for monitoring, reporting and verification (MRV) during site operation. These regulations would distinguish CO2 storage from EOR and enhanced gas recovery projects.

An important aspect of CO2 storage regulations would be the ongoing demonstration that a storage reservoir would retain at least 99 percent of the injected CO2 for at least 1,000 years. These regulations would include performance measures, design standards, and MRV for preventing CO2 emissions to the atmosphere, and protecting human health and the environment.

Suitable geologic formations exist in California for CO2 storage in oil and gas reservoirs and saline aquifers. These reservoirs are common in deep sedimentary basins, where great thicknesses of sandstone and shale layers have accumulated over many millions of years. This layered sequence of rocks are good storage sites, because they have the capacity to hold (trap) large amounts of CO2 in the pore spaces of the more permeable sandstone layers, while overlying less permeable shale layers act as cap rocks to prevent the escape of CO2. At depths

below 2,500 feet (800 meters) optimal sequestration takes place. At that depth the pressure and the temperature are such that CO2 is in a liquid-like supercritical state, making it less buoyant.

From a material standpoint, CO2 is a non-toxic and nonflammable gas. Animals and humans exhale CO2 and plants uptake CO2 for photosynthesis. However, past experience with naturally occurring CO2 emissions from volcanic activity shows that accumulation of CO2 in poorly ventilated depressions could pose a risk of asphyxiation in animals and humans and high concentrations in the soil will stress vegetation. Therefore, careful consideration is given to the selection of the pipeline route and the storage reservoir to guard against leakage during operation and after injection stops.

Induced seismicity is another risk of CO2 injection operations. It has been demonstrated that the injection of fluids into the subsurface can result in seismic events. Most of these induced seismic events are not documented as earthquakes, because they do not release enough energy to be felt at the surface. Therefore, seismic risk is an important consideration in reservoir selection, and in the design, operation, and monitoring of CO2 storage. The identification and proximity to active faults is an important geologic criterion in reservoir selection. In addition, specialized seismic monitoring will likely be required in the MRV plan.

CO2 is not a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund). Therefore, the sequestration of CO2 in a storage reservoir should not cause a CERCLA liability. However, the sequestration of CO2 could cause a CERCLA liability if the following occurs:

- The CO2 contains impurities that are CERCLA hazardous substances
- The capture process releases CERCLA hazardous substances
- The CO2 reacts with subsurface substances or groundwater to produce a CERCLA hazardous substance

### 1.4.4.2 Permitting of Class VI CO2 Injection Wells

The EPA is currently the lead agency in California for the UIC program. The EPA can, however, delegate its authority to a state agency for permitting Class VI wells, which is a new class of injection wells for CCS. The EPA under the UIC program, as authorized by the Safe Drinking Water Act, establishes requirements for the underground injection of CO2 for CCS to ensure the protection of underground sources of drinking water (USDW) from injection related activities.

The State should evaluate EPA regulations and determine if the Department of Oil, Gas and Geothermal Resources (DOGGR) should seek "authority" for permitting Class VI wells under the UIC program. DOGGR currently regulates the drilling and operation of wells that are classified as Class II wells under authority from the EPA. DOGGR sets requirements for any injection of fluids for EOR or the enhanced recovery of natural gas, or for fluids that are brought to the surface as a result of conventional oil or natural gas production.

### 1.4.4.3 Ownership and Use of the Pore Space in the Reservoir

There is currently no established rule in California that governs the ownership or use of the pore space in a reservoir for CO2 storage. However, CCS cannot occur without the right to inject and store CO2. Therefore, ownership of the pore space in a reservoir needs to be clarified as to which parties retain ownership and liability of the injected CO2.

Pore space ownership could be clarified by legislation that the pore space belongs to surface land owner. This would be consistent with other states, and the handling of pore space for oil and gas production and natural gas storage. Although, the legislature could choose to declare the pore space to be a public resource; the mechanisms to acquire pore space rights for CCS projects also need to be addressed.

### 1.4.4.4 Long-term Liability of CO2 Storage

For CCS to be effective, CO2 must remain underground for periods of time that could last hundreds to thousands of years, which is beyond the historic life-span of most companies and many governments. This requires institutional, administrative, and regulatory approaches for long term stewardship to protect the public.

This aspect could be a major barrier for industry to undertake CCS projects, because of the undefined and open-ended liability for the CO2 storage site. Although the risks associated with the injection of CO2 in EOR operations have been managed for many years, the long-term liability for CCS may be unique.

# CHAPTER 2: Summary of Engineering Options Analysis Procedure and Site Assessment

### 2.1 Development of Engineering Options Analysis Procedure

CB&I developed an Engineering Options Analysis Procedure as a tool to compare the costs, performance impacts, and risks associated with implementing CO2 capture technology at California NGCC plants. There are separate procedures for the retrofit of NGCC plants with CCS and for the integration of CCS into new NGCC plants in the development stage. The procedures are essentially the same with differences to account for retrofitting CO2 capture on an existing plant vs. implementing CO2 capture during the design phase of a new plant. In order to compare the costs, performance impacts, and risks associated with CO2 capture technology at NGCC plant sites, CB&I developed a Model to quantify and compare each option. The Modeluses a set of costs and performance input values to calculate the lifecycle levelized COP for a given scenario. The levelized COP is a simple, yet valuable metric that compares the economics of different options on a consistent basis. Levelized COP is defined as the price per unit of production that must be charged over the life of the project in order for the net present value (NPV) of the project cash flows (including both the revenues and costs) to equal zero. The levelized COP includes the effects of different costs, performance characteristics, and supplementary revenue streams and accounts for the time value of money. A visualization of the levelization of costs for a representative combined cycle plant is shown in Figure 2 below:

1 4 7 10 13 16 19 22 25 28 31

Capital \*\*O&M\*\* Fuel\*

Figure 2: Levelization of Costs

Source: CB&I

In the case of evaluating retrofit options, the Model is set up to evaluate retrofitting existing NGCC plants with CCS by utilizing the incremental costs and performance of adding the CCS. In the case of comparing different New Build options, the Model is set up to compare a base option of an NGCC plant with no CO2 controls with different options for integrating carbon capture with new NGCC plants under development. The impact of the CO2 transportation pipeline and injection system is also included in the incremental costs and performance. The key difference between the retrofit procedure and the new build procedure is that the retrofit considers all the cost, performance and revenue impacts (or increments) of the CCS to the plant before the retrofit occurs, whereas the new build procedure considers the cost, performance, and revenue of a complete NGCC plant with CCS and compares those economic elements (cost, performance, revenue) to a typical NGCC without CCS.

### 2.1.1 Model Organization

The Model is an Excel spreadsheet that includes the following worksheets:

- Title
- Cost and Performance Inputs
- Economic and Price Inputs
- Levelized COP Evaluation
- Summary Charts and Tables

The following sections provide a description for each of the worksheets, the inputs used in the Model, and the outputs derived from the Model. Inputs to the Model are differentiated and entered in blue cells while the remaining cells are calculation cells. Inputs are contained in the Cost and Performance Inputs and Economic and Price Inputs worksheets. The cost and performance inputs for all of the options being compared are contained in the Cost and Performance Inputs worksheet. Inputs are taken from these sheets and used in the Levelized COP Evaluation worksheet to calculate the levelized costs for all the options. Summary and sensitivity charts and tables are included in the Summary Charts and Tables worksheet.

### 2.1.2 Cost Inputs

The carbon capture technology capital cost information is from estimates prepared by the CB&I estimating group with input from CB&I power generation services group. The O&M costs are from estimates prepared by the CB&I power generation services group including budgetary estimates from the various carbon capture technology suppliers and staffing data from the participating utilities.

The cost components of the Model consist of the following:

- Capital costs
  - o to retrofit the plants with a carbon capture system
  - o for new NGCC plants with a CCS (and the base case NGCC plant without CCS)

- Capital costs for a CO2 transportation pipeline and injection system
- Plant O&M
  - o Incremental fixed and variable O&M cost for the CCS
  - Fixed and Variable O&M cost for the plant including the CCS
- CO2 transportation pipeline and system O&M
  - o Incremental fixed and variable O&M cost for the retrofit option
  - o Fixed and variable costs for the new build plant
- Carbon penalty (also referred to as carbon emissions allowance cost)
- Replacement power (retrofit only)

## 2.1.2.1 Capital Cost

The capital costs were developed based on EPC cost, owner's cost, interest during construction, inflation and escalation, and project contingency. For the retrofit case, the EPC cost is divided into two components including the EPC costs for the carbon capture system and the CO2 transportation and injection system. The EPC cost for the carbon capture system is the incremental EPC cost for a system to capture and compress the CO2. The carbon capture and compressor system EPC cost estimate is based on publicly available cost information, information assembled from the carbon capture system and compressor suppliers, and applicable experience based costs derived by the CB&I estimating group. The construction period is a typical expected length of time to implement the carbon capture and compression system based on CB&I's recent construction experience with large scale air quality control systems, which include flue gas desulfurization and selective catalytic reduction flue gas stream modifications. The design and cost basis further described in Chapter 3.

The EPC cost for the CO2 transportation and injection system includes the CO2 transportation pipeline, compressor booster stations, and wellhead/underground injection system. The CO2 transportation pipeline, compressor booster stations, and injection system EPC cost estimate is based on publicly available cost information, some information from technology suppliers and other costs derived by CB&I using its database of cost information, productivity, labor cost and indirect cost adjustments. The construction period is a typical length of time to install the CO2 transportation pipeline and injection system. The design and cost basis further described in Chapter 3.

In the case of the new build, in addition to the carbon capture system and the CO2 transportation and injection system components, a third component is included for the cost of a new NGCC plant based on costs derived by the CB&I estimating group. The construction period is a typical length of time to build a new NGCC plant. Additional details are described in Chapter 4.

## 2.1.2.2 Plant Operation & Maintenance Costs

The O&M costs consist of fixed and variable O&M costs. The O&M costs cover the costs needed to operate and maintain the carbon capture system, the CO2 transportation and injection system, if applicable, and, for the new build evaluations, the new NGCC plant. The O&M costs do not include fuel costs, replacement power costs, or carbon penalty costs (also referred to as carbon emissions allowance cost). As discussed in more detail in the Economic Assumptions section, the first year O&M costs are increased over the operating life of the plant using general inflation and O&M escalation adders.

## Fixed Operation & Maintenance Cost

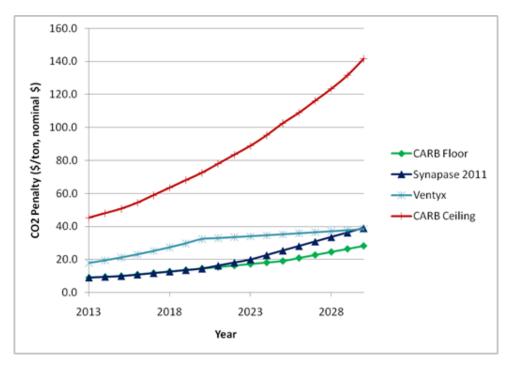
For the retrofit evaluations, two line items are included in the Model to account for the annual incremental fixed O&M cost: (1) for the carbon capture system and (2) for the CO2 transportation pipeline and injection system. The fixed O&M cost is the annual cost to capture carbon that does not vary depending on the amount of electricity production. The fixed O&M costs include any ongoing capital improvements or replacements associated with the installed systems that were not included in the upfront capital costs. For the new build evaluations, the fixed O&M costs for the NGCC plant are also included in the evaluation.

#### Variable Operation & Maintenance Cost

For the retrofit evaluations, two line items are included in the Model to account for the incremental variable O&M cost: (1) for the carbon capture system and (2) for the CO2 transportation pipeline and injection system. The variable O&M includes the O&M costs that vary depending on the amount of carbon that is captured. It is expressed as a cost per year divided by the annual amount of CO2 removed by the retrofit system. The variable O&M for the carbon capture system includes the cost of solvents/reagents, makeup water, solvent/reagent disposal, and waste water disposal. Note that variable O&M does not include the power required to operate the compressors that are part of the plant carbon capture system as these loads are internal to the plant and are accounted for in the replacement power category. However, the CO2 transportation and injection system costs are directly included, then the power required for the CO2 transportation and injection system is included in the O&M cost as it is external to the plant. For the new build evaluations, the variable O&M cost for the NGCC plant are also included in the evaluation.

## 2.1.2.3 Carbon Penalty

The proposed California cap-and-trade plan includes a limit on the total CO2 emissions that may be emitted and proposes to decrease that limit on a year-by-year basis. The plan allows for allowances to be purchased covering each metric ton of CO2 emissions that is not captured. This allowance is included in the Model as a carbon penalty (also referred to as carbon emissions allowance cost). It is expected that the carbon allowance price will start low but will increase as the allowance demand increases. Figure 3 includes a graph that CB&I developed of carbon allowance prices from the CARB floor price, the CARB ceiling price, the Synapse 2011 projected price and the Ventyx projected price used in the power market forecast.



**Figure 3: Carbon Allowance Price** 

Source: CB&I

For modeling purposes, CB&I has assumed that the base case carbon allowance price is as projected by Ventyx. A CO2 emissions penalty price of \$18.40/ton CO2 in the first year of operation with 7 percent escalation thereafter is consistent on a lifecycle average basis with the CO2 penalty projected by Ventyx.

The annual carbon penalty cost is the product of the CO2 emissions by the CO2 penalty price per unit of CO2 emitted. The CO2 penalty price is discussed in more detail in the Model Economic and Price Inputs in Section 2.1.5.

#### 2.1.2.4 Replacement Power (Retrofit evaluation only)

Replacement power cost is the cost of power that an existing plant would need to purchase in order to make up for the reduction in electricity production after the carbon capture system retrofit. Beginning with a constant fuel input, replacement power accounts for the decrease in power output from cycle steam use, and the power consumption of the carbon capture system. The first year of replacement power cost is assumed to be \$65/MWh with 1 percent real escalation and 0.4 tons CO2 emitted per MWh based on replacement power being provided by a new combined cycle plant. The sensitivity cases are associated with different sources of replacement power (renewable case and grid mix case).

#### 2.1.2.5 Fuel Cost

The study considers implementing carbon capture technologies in power plants with a fuel type of natural gas. For the retrofit evaluations, the cost of fuel is not directly included in the Model. The plant fuel input rate is assumed to be the same before and after the carbon capture system

retrofit. The reduction in efficiency and the reduction in electric output are accounted for with the replacement power cost. Any reduction in fuel cost due to reduced capacity factor is also accounted in the replacement power cost category. For the new build evaluations, fuel costs due to differences in fuel consumption between the base case NGCC plant without carbon capture and the NGCC plant with carbon capture is included in the Model.

## 2.1.3 Performance Inputs

In order to evaluate the impact that the carbon capture system has on the plant economics the performance before and after (in the case of the retrofit cases, or with and without in the case of the new build cases) the carbon capture system is included in the Model. The performance that is impacted by the carbon capture system includes:

- Capacity
- Heat Input
- Availability
- Capacity factor
- CO2 emissions

For modeling purposes, CB&I has combined publicly available performance information with specific information for each of the plants. This performance data has been adjusted to account for the addition of CCS.

## 2.1.3.1 Capacity

The Model includes the gross and net electric capacity before and after the carbon capture retrofit, or, in the new build cases, with the carbon capture system compared to a NCGG plant without the carbon capture system. The gross electric capacity of the plant with the carbon capture system is reduced due to the effects of extraction of steam for the carbon capture system from the power cycle. The net electric capacity of the plant with the carbon capture system is reduced due to the increase in auxiliary loads attributed to the carbon capture system. The capacity reduction varies based on the carbon capture technology system and ranges from a reduction of 19 percent to 23 percent.

#### 2.1.3.2 Heat Input

The Model includes a heat input (MMBtu/hr, higher heating value) based on the existing plant operation for the retrofit evaluation. The heat input remains constant before and after installation of the carbon capture system. For the new build evaluation, the base case plant without carbon capture is assumed to have the same heat input as the new NGCC plant with carbon capture. In all cases, the heat rate is an indicator of efficiency derived from electric capacity divided by heat input.

## 2.1.3.3 Availability

For the retrofit evaluation, each plant's historical availability factor and the expected lifetime average annual plant equivalent availability were noted for each plant without a carbon capture system. For the new build evaluation, the availability of a typical NGCC without carbon capture was included as an input. This data is used as a starting point and the impact, if any, the carbon capture system might have on the plant availability due to planned maintenance and potential for increased forced outages is incorporated in the expected lifetime average annual plant equivalent availability with a carbon capture system.

The projected availability for a combined cycle plant with a carbon capture system considered the following:

- The carbon capture system can be bypassed for planned and unplanned outages.
- For cost containment reasons, there are no major equipment redundancies provided in a carbon capture system.

## 2.1.3.4 Capacity Factor

For existing plants the historical average annual capacity factor was noted based on public information. For both the retrofit and new build evaluations, the expected lifetime average annual plant capacity factor is determined based on the results from the Ventyx Market Analytics<sup>TM</sup> market simulation model, which employs the PROSYM<sup>TM</sup> analytical engine. The capacity factor was used to determine the difference in power generation as a result of including the carbon capture system.

## 2.1.3.5 CO2 Emissions

The CO2 emissions (tons/hr) were calculated based on the capacity factor determined in the market simulation model for each plant including the CO2 recovery rate guaranteed by the carbon capture system supplier.

## 2.1.4 Revenue Inputs

Typically levelized cost comparisons only consider direct electrical energy costs because electricity is the product and the only source of revenue. For a levelized cost comparison involving plants that have other sources of revenue besides electricity, credits or reductions are given for the other sources of revenue. This Model is set up to account for a reduction in ancillary services revenue due to a lower capacity and less generation or an additional revenue source of CO2 sales for EOR. Based on guidance from the Energy Commission, CB&I has not included the financial benefits of selling the CO2 for EOR.

## 2.1.5 Economic and Price Inputs

The Model economic and price inputs are included on the Economic and Price Inputs worksheet. Key economic assumptions include the levelized annual capital recovery rate, discount rate, inflation, escalation, economic life, and CO2 emissions associated with the replacement power (retrofit evaluation only). The cost reference year is 2012. It is assumed that the carbon capture system (and new NGCC plant for the new build evaluation) design and

construction begins to support an in-service date of 2015. To ensure a consistent comparison all the economic and price inputs remain the same for each option being evaluated.

#### 2.1.5.1 Inflation and Escalation

Inflation and real escalation rates are included in the Model for the price and cost inputs to account for increases in prices and costs over the project life. Table 3 summarizes the values used for general inflation, real capital cost escalation, real electricity/steam price escalation, real O&M cost escalation, real CO2 penalty price escalation, real CO2 sales escalation, and real ancillary services revenue escalation.

**Table 3: Inflation and Escalation Rates** 

General inflation	1.7%/year
Real capital cost escalation	0%/year
Real electricity/steam escalation	1%/year
Real O&M cost escalation	0%/year
Real CO <sub>2</sub> penalty price escalation	7%/year
Real CO <sub>2</sub> sales escalation	1.2%/year
Real ancillary services revenue escalation	1%/year

Source: 2012 EIA AEO, Ventyx model, USDA Economic Research Service, CB&I

The nominal escalation is calculated based on the above listed real escalation rates and the general inflation assumption.

#### 2.1.5.2 Discount Rate

The discount rate was calculated using the debt to equity ratio, return on equity rate, cost of borrowing, and the effective tax rate on net income. The discount rate is specified in real terms (i.e., without the effect of general inflation). The discount rate can be adjusted by using different assumptions to build up a weighted average cost of capital, which is often used for a risk-free rate; beta; market risk premium; debt ratio; cost of debt; and an effective tax rate on net income. General inflation is added in separately and is used to calculate the nominal discount rate. A real discount rate of 8 percent is used in the Model. This discount rate is representative of a typical IOU financed project. A sensitivity range of 6 percent - 10 percent is included to represent a public utility project financing at the low end and an independent power project financing at the high end.

## 2.1.5.3 Income Taxes and Depreciation

The corporate income tax rate is determined using a federal income tax rate and the corporate income tax rate for California. The effective tax rate is calculated by adding together the federal and state rate and reducing it by the product of the rates to account for deduction of the state income tax from the income on which the federal tax is based. The effective tax rate is 40.7

percent, a combination of the federal corporate income tax rate of 35 percent and the California state corporate tax rate of 8.8 percent.

The depreciation schedule is the 20 year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule as specified in Internal Revenue Service (IRS) Publication 946. Economic life is the period over which the economics are evaluated and over which the capital recovery takes place, which is assumed to be a nominal 20 years for each plant.

## 2.1.5.4 Capital Recovery Rate

The levelized annual capital recovery rate is calculated based on the discount rate, economic life, depreciation schedule, and effective tax rate.

## 2.1.5.5 Price Inputs

The Model includes prices for the first year of operation as shown on Table 4.

Table 4: Price Assumptions – First Year of Operation

Value of replacement power	\$98/MWh
Natural gas price	\$4.56/MWh
CO <sub>2</sub> penalty price	\$18.4/ton CO <sub>2</sub>
Ancillary services price	2% of energy revenues
CO <sub>2</sub> sales	\$10/ton CO <sub>2</sub>

Sources: 2012 EIA AEO, Ventyx model, CB&I

Levelizing factors are calculated to convert the first year cost into a levelized cost over the economic life of the project. The levelizing factor calculation includes the nominal escalation rate, economic life, and discount rate.

## 2.1.6 Model Outputs

The use of a levelized cost model enables the comparison of options using simple metrics and makes it easy to conduct sensitivity analyses for key input parameters. The annual levelized cost can be divided by different annual production values to form key metrics. The annual production values are assumed to remain constant over the economic life. The key metrics for a comparison of retrofit and new build options are:

- Total Levelized COP, \$/MWh (New Build cases only).
- Incremental Levelized COP, \$/MWh.
  - o For retrofit cases: Power production based on power production with carbon capture plus replacement power (which is the same as the power production without carbon capture).

- o For new build cases: Levelized COP of new build option with carbon capture minus the levelized COP of the base case with uncontrolled emissions.
- Incremental Levelized \$/ton CO2 captured.
  - o CO2 captured is simply the amount of CO2 captured by the carbon capture system.
- Incremental Levelized \$/ton CO2 avoided.
  - o CO2 avoided is calculated as the difference in CO2 emissions with and without carbon capture, with the CO2 emissions after carbon capture including any CO2 emissions associated with replacement power (retrofit cases only).

Each of these metrics can be shown as a sum of the following components: capital cost recovery, replacement power (retrofit cases only), O&M, carbon penalty, and ancillary services revenue reduction.

## 2.2 Select Sites at Which to Apply the Engineering Options Analysis Procedures

## 2.2.1 Analysis

CB&I prepared a list of existing California power plants to analyze as potential sites to be evaluated in the application of the Engineering Options Analysis Procedure for retrofitting an NGCC plant with CCS and for implementing a CCS in a New Build NGCC plant. In order to select the sites for which the CCS could be retrofitted in an existing plant or incorporated in a new build project, CB&I developed a Comparison Matrix of Plant Sites to facilitate analyzing each potential site. The Comparison Matrix of Plant Sites provided a simple and clear means for evaluating the following key criteria used to select a site location for the Study.

The nine key criteria are listed below:

- 1. Does the site have the configuration of generating units applicable for evaluation (newer than year 2000, "F" class, duct firing, 2x2x1 or larger configuration)?
- 2. Has site Owner/Operator indicated a willingness to participate?
- 3. Is sufficient information available to support the engineering options analysis?
- 4. Does the site have sufficient space for addition of a CCS?
- 5. Does the site have sufficient water available to support a CCS?
- 6. Does the site have sufficient waste water permits to support a CCS?
- 7. Does the site have access to potential CO2 storage?
- 8. Is the site reasonably accessible for delivery of new CCS equipment and reagent supply?
- 9. Does the site have special operational requirements such as grid support or export steam contracts that would limit the flexibility to accommodate a CCS retrofit?

The higher ranking a site received relative to other sites in meeting a key parameter indicates a preference for selecting that site over other sites. If a site was not selected for evaluation in the Study does not reflect on whether CCS is viable at the site.

To populate the Comparison Matrix of Plant Sites, CB&I prepared and provided a request to participate in the Study and a questionnaire to the site Owner/Operators listed in the WESTCARB Study. For those plants that did not respond publically available information, data, and documents including information that was available in the WESTCARB Study were used to develop the inputs to the Comparison Matrix of Plant Sites. The historical capacity factors and steam cogeneration capacity, taken from the QFER CEC-1304 Power Plant Owner Reporting Database, were used in the Comparison Matrix of Plant Sites.

#### 2.2.2 Results

Using the methodology described above, the top three existing plant sites were:

- 1. Colusa = 84 percent
- 2. Gateway = 80 percent
- 3. Mountain View = 72 percent

Given the methodology, these high rankings are based primarily on the expressed willingness of the Owners to participate. However, data sheets were not provided for any of these plants. Therefore, CB&I developed an enhanced methodology that concentrated on site characteristics by eliminating the parameters: Willingness to Participate and Availability of Information. The sites were ranked primarily on their geospatial and sequestration characteristics. Using the enhanced methodology, the top three existing plant sites were:

- 1. Valley = 93.5 percent
- 2. Gateway = 92.5 percent
- 3. Haynes = 92.5 percent

The Study used the Gateway Power Station (Gateway) to apply the Engineering Options Analysis Procedures for retrofitting an NGCC plant with CCS.

There are three new build plants on the WESTCARB list that are viable sites and are not under construction. The enhanced methodology ranks these plants as:

- 1. CPV Vaca = 91 percent
- 2. Willow Pass = 82 percent
- 3. Carlsbad = 73 percent

Since the listed new-build plants are still in the review process, there is a possibility that the major equipment could be modified for integration with a CCS system. CB&I recommends proceeding with the new build site analysis based on these sites and the reference  $2 \times 2 \times 1$  NGCC Power Island developed in support of the technology selection. For this analysis, the

reference power island cycle and equipment will be modified to optimize integration with the CCS system by selecting steam supply and condensate water return points that result in the best overall plant efficiency.

The Study used the CPV Vaca Power Station to apply the Engineering Options Analysis Procedures for implementing a CCS in a New Build NGCC plant.

## **CHAPTER 3:**

# Preliminary Engineering Design and Analysis for Ngcc Plant Retrofit With Co2 Capture System

## 3.1 Overview

The Retrofit Engineering Options Analysis Procedure was developed to provide a tool to compare the costs, performance impacts, and risks of implementing CO2 capture technologies at existing California NGCC plant sites. Gateway was selected as the representative California NGCC plant to be used to evaluate the cost and performance of retrofitting a NGCC plant with CCS. Gateway is a 530 MW natural gas-fired power plant in Antioch, California and is operated by the San Francisco-based Pacific Gas & Electric.

## 3.2 Preliminary Engineering Design for Retrofit Analysis

In the absence of specific plant data for Gateway, a reference plant was developed from the CB&I database. This reference plant is a nominal 550 MW, GE Frame 7 FA, 2x2x1 combined cycle arrangement which is a similar configuration to Gateway. Using the Thermoflow Thermoflex heat balance software, the heat balance was revised for the ambient conditions in the Contra Costa (Antioch, California) area so as to be more representative of Gateway. In addition, the cooling system was an air cooled condenser to minimize water usage.

The reference plant includes the following optimizations.

- The height of the absorber vessel was deemed sufficient to allow the flue gas to exit from a short stack on the top of the absorber, thus eliminating the cost of the ducts returning to the existing HRSGs' stacks.
- The heat and mass balances were based on annual average ambient conditions that are representative of the 50 percent percentile occurrence rather than the most demanding summer 2½ percent occurrence ambient conditions.
- The carbon capture system cooling water loop temperature is 78°F at annual average conditions and results in a significant reduction in parasitic power consumption.
- The CO2 compressor cooling is forced air cooled. The hot air from the compressor cooling was ducted to the exhaust stack to increase the temperature of the exiting flue gas.
- Hypothetical modifications were made to the HRSGs to reduce the flue gas exit
  temperature to the 200°F range. A cost of \$4 million was added to the power island
  retrofit capital cost to cover these modifications.

## 3.2.1 Carbon Capture Technology

Three post combustion technologies for retrofit applications that were identified as described in Chapter 1 were to be applied to a reference plant that had a strong sequestration potential. However, the three carbon capture technologies were further evaluated before proceeding with the evaluation of the retrofit project. It was determined that two of the technologies (Case A and Case C) would not be evaluated further for the following reasons:

- Case A will not be evaluated further because it is conventional MEA and has been studied and demonstrated extensively.
- Case C was not selected because it is still in the laboratory stage and is not ready for large scale application.

Case B was selected because it is an advanced amine technology that has been demonstrated and is offered commercially by several suppliers.

## 3.2.2 Carbon Capture Process Description

To enable the capture of CO2 from the CT flue gas streams, new ductwork sections including isolation dampers will be installed at the flue gas discharge ends of both HRSGs before the flue enters the stacks on both units, and within the new ductwork sections. New isolation dampers located at the base of each stack where it connects to the HRSG will be closed whenever the CO2 capture equipment is operating to ensure all flue gas is diverted to the CO2 capture plant. Additional dampers will be located in the new ductwork from each HRSG that feeds flue gas to the CO2 plant and will be normally open when the CO2 capture equipment is in operation. Flue gas return ductwork from the CO2 plant will not be required since a new stack will be included on the absorber. This damper configuration allows the flue gas from each CT to be diverted either to the common CO2 capture plant before it enters the existing stack, or it can bypass the CO2 capture plant and be directed to the existing stack for that unit and discharged to atmosphere in the same manner as existing operations.

New flue gas ductwork from each HRSG will be routed overhead to the new CO2 absorber starting at the existing HRSG/stack interconnecting ductwork fitting and will continue to the inlets of the flue gas cooler that lowers (and maintains) the gas mixture to near saturation before it enters the process equipment. Two 50 percent booster fans configured in a parallel arrangement are provided between the cooler and the CO2 process equipment. Booster fans are necessary to help overcome the additional pressure drop in the flue gas ductwork associated with the addition of the new CO2 process equipment. Flue gas from the booster fans is directed to a large absorber vessel. Once inside the absorber, the flue gas stream is mixed (scrubbed) with a special solvent which subsequently releases CO2 from the flue gas and then it is absorbed into the liquid solvent. The absorber vessel is located adjacent to the flue gas cooler to help reduce the length of ductwork runs. The treated flue gas exists to atmosphere through a short stack on top of the absorber.

CO2 that has reacted and combined with the liquid solvent inside the absorber flows from the bottom of the absorber vessel along with the solvent through a heat exchanger that heats up the CO2 "rich" mixture before it enters a large stripping vessel. The rich solvent mixture is

preheated in the heat exchanger by the lean (regenerated) solvent which is continually recycled from the stripper vessel back to the absorber for reuse in the process. On-site solvent storage and makeup systems are included in the design to ensure a continuous source of solvent is always available for the CO2 capture process.

Inside the stripping vessel, CO2 is released from the solvent mixture by the addition of heat. Once in the gaseous state, the CO2 is ducted from the stripper vessel to a cooler that condenses any remaining gaseous solvent and returns it to the stripper. After cooling, the CO2 undergoes final cleanup to remove any remaining impurities before compression. Heat is supplied to the stripper vessel from a "reboiler" that uses low pressure steam supplied from the main generating plant. Condensate from the CO2 process is continually collected and returned to the power cycle.

Once separated from the solvent, CO2 undergoes cleanup to remove any impurities including a dehydration step to help remove any residual moisture, before entering the compressors. Compression of CO2 is accomplished by installing multiple stage compressors located adjacent to the capture plant. The new compressors are designed to compress the CO2 to approximately 2200 psig and will discharge directly into a sequestration pipeline. Because this equipment is large, it will be located on site to facilitate maintenance and repair operations.

Power will be supplied to each unit's new CO2 process equipment from a new and separate dedicated transformer. The transformer will be fed from the existing switchyard and located as close as practical to the existing high voltage source. A new electrical and control room building will be provided for the new CO2 capture facility. Control of the CO2 process will be from a new dedicated programmable logic controller (PLC) located inside the new control room. Pertinent data will be fed back to the plant's main control room for remote monitoring capability and added safety. Plant communications will also be interconnected to the new carbon capture plant along with major alarms.

Makeup water supplied to the new CO2 process equipment will be supplied from the existing main plant cooling water system. The existing water treatment facility will be expanded to accommodate the increase in makeup water and will be cross-tied to the existing main plant treatment system for added reliability.

## 3.2.3 Design and Operating Parameters for Advanced Amine Technology

The carbon capture technology Case B is an advanced amine absorption technology with key elements of the system that include:

- Direct contact cooler for flue gas entering the system
- CO2 absorber (gas-liquid contactor) with water wash section
- Solvent regenerator (stripper)
- Stripper reboilers
- Stripper overhead condenser and knockout drum(s)

- Rich/lean solvent exchanger(s)
- Interconnecting pumps, piping, ducting

Table 5 and Table 6 summarize the key advanced amine technology parameters for a CCS system.

**Table 5: General CCS Parameters** 

Ambient pressure	14.67	psia
Ambient temperature	61	°F
Ambient Relative Humidity	68.66	%
Gross power	506,246	kW
Net power	453,554	kW
Net heat rate <sup>1</sup>	8,111	Btu/kWh

Heat rate is based on a higher heating value (HHV)

Table 6: CCS Parameters - Advanced Amine Technology

Description	Flow	Pressure	Temp	Enthalpy
Description	klb/hr	psia	°F	Btu/Lb
HRSG Exhaust (per Unit)	3,571	14.84	201.4	31.40
Total Flue Gas Without Treated CO <sub>2</sub> Stream	6,599	14.74	95.0	4.496
Total Flue Gas and Air to Stack	9,318	14.67	121.20	
CO <sub>2</sub> Compressor Cooling Air Fan Inlet	2,754.9	14.67	61.0	
CO <sub>2</sub> Compressor Cooling Air Fan Outlet	2,754.9	15.39	70.0	
CO <sub>2</sub> Compressor Cooling Air Out to Stack	2,719.2	14.74	186.6	
High Pressure CO <sub>2</sub> Product	385.0	2,200	116.0	
Steam from Turbine to CO <sub>2</sub> Capture System Reboiler	416.3	77.67	646.7	1,353.7
Desuperheating Water to CO <sub>2</sub> System Reboiler Steam	66.80	240.3	103.8	72.43
Steam to CO <sub>2</sub> Capture System Reboiler	483.1	52.21	289.0	1,176.5
Condensate from CO <sub>2</sub> Capture System Reboiler	483.1	50.0	281.0	250.3
CO <sub>2</sub> Capture System Reboiler Condensate	241.6	350.0	281.5	251.4

Description	Flow	Pressure	Temp	Enthalpy
Description	klb/hr		°F	Btu/Lb
to Each HRSG				
CO <sub>2</sub> Capture System Makeup	0			
CO <sub>2</sub> Capture System Discharge to Waste	52.6	14.67	97.10	65.14
Flue Gas Cooler Discharge to Waste	105.5	14.67	105.10	73.16
Cooling Water to CO <sub>2</sub> Capture System	37,654	55.0	76.00	44.27
Cooling Water from CO <sub>2</sub> Capture System	37,654	20.0	98.62	66.66

Source: CB&I

## 3.2.4 Retrofit Impacts

CB&I considered the impacts of retrofitting the carbon capture system on the existing plant according to the following areas:

- Interface requirements
- Major plant modifications to systems and equipment
- Plant performance
  - o Capacity, heat input, and heat rate
  - o Water requirements
  - o Capacity factor
  - o Availability
- Required equipment and space
- Modifications to water and wastewater
- Flue gas pretreatment
- Operations including operating flexibility and staff costs
- Environmental
- Carbon emissions

Each of the impacts listed above are described below.

## 3.2.5 Interface Requirements

The following is a list of interfaces between the main plant and the new CO2 capture equipment:

• Flue gas ductwork and associated connections at both existing stacks.

- Steam supply from the existing ST including condensate return to the HRSG.
- Raw water supply and return to the existing water treatment facility.
- Process water waste from the new CO2 system to the existing wastewater treatment and disposal system.
- Power connection at the existing switchyard for new transformer.
- Electrical grounding and cathodic protection.
- Plant communications systems.
- Plant control systems.
- Fire protection systems.
- Additional maintenance and parts storage facilities.
- Disposal of all waste material generated by the new CO2 capture process.
- Potable water and sanitary systems including personnel facilities.
- Parking for additional employees.

## 3.2.6 Major Plant Modifications

The following list identifies major plant modifications required for installation of the new CO2 capture equipment:

- Modifications at various locations within the existing plant will be required to accommodate steam, water, controls and electrical power interfaces.
- Some existing communications, electrical, piping and security equipment may need to be modified or relocated to help provide additional space for the new CO2 capture equipment.
- Some existing roads within the plant will need to be reconfigured and resurfaced.
- Underground utilities in the vicinity of the new CO2 capture equipment will need to be relocated due to interferences.
- Existing overhead power lines need to be relocated in the area of the existing switchyard.

## 3.2.7 Plant Performance - Heat Input, Capacity and Heat Rate

Since the original heat balances for Gateway were not provided, CB&I produced heat balances for Gateway using Thermoflex software by the Thermoflow Corporation. It was assumed that Gateway's heat input will remain constant with and without a carbon capture system. CB&I developed a cycle model using in-house data for the Power Island and information from the advance amine technology suppliers for the CCS system for a generic NGCC. To best emulate Gateway, CB&I used the program configuration that consists of two General Electric (GE) 7FA

CTs with two HRSGs and one ST (the 2x2x1 configuration). The ST is of a reheat design with a low pressure steam induction point. It ihas a single-flow design using high pressure (HP) steam; reheat steam at an intermediate pressure steam and low pressure (LP) steam. The plant uses only natural gas for fuel. There is a fuel gas heater, which heats the CT fuel to 365°F using the HRSG intermediate pressure (IP) economizer discharge water. Gas used for duct burners is not heated. CTs have inlet air chilling for use during the hottest times of the year. Chilling is not used in this Study as the average annual ambient temperature is relatively low, 61°F.

Two heat balances were produced; one for the CO2 Capture System ON and one for the CO2 Capture System OFF. The CO2 capture system operation causes significant degradation in overall cycle performance. This is due to the extraction of intermediate pressure-to-low pressure (IP-LP) cross-over steam for the system reboiler and for the large auxiliary power requirements. The performance breakdown in Table 7 is as follows:

Table 7: NGCC Plant Performance - without and with CCS

CO <sub>2</sub> Capture System Operating	No	Yes
Gross Plant Generation, MW	543	506
Total Auxiliary Power, MW	12	53
Net Plant Generation, MW	531	454
Net Plant Heat Rate, Btu/kWh	6,951	8,111
Gross Generation Reduction Due to Reboiler Steam Extraction, MW		37
Auxiliary Power Difference, MW		40
Total Net Power Reduction Due to CO <sub>2</sub> Capture System, MW		77

Source: CB&I

A major aspect of this Study is that all dry cooling is to be used. This includes an air-cooled condenser for the main power cycle, fin-fan coolers for the auxiliary cooling system water, fin-fan coolers for the CT inlet air chiller water, and fin-fan coolers for the CO2 capture system CO2 stripper outlet cooling water, and direct air cooling for the CO2 Compressors.

The CO2 compressors are air cooled and data from one of the manufacturers is used in this study. The compressor has eight stages with intercooling between each stage and an aftercooler. These heat exchangers were modeled with CO2 on one side and cooling air on the other. An air fan (blower) is used with enough quantity of air to keep the CO2 which is being compressed to reasonable interstage and afterstage temperatures. The CO2 exiting the last compressor stage is then assumed to be routed to its final destination. The air heated by the

compressor is routed to the exhaust stack, which increases the flue gas exhaust temperature from 95°F to 121°F.

## 3.2.8 Water Requirements

CB&I optimized heat balances to minimize the cooling loads required by the CO2 capture cooling system design. Solvent suppliers confirmed that the solvents will work at 80°F as a result of reducing the cooling load, although the solvent effectiveness decreases. The optimized heat balances indicated that operation at annual average conditions without a chiller would produce 78°F cooling water. Evaluation of monthly average temperatures also supported the elimination of the chillers if higher solvent temperatures and consequently reduced solvent effectiveness were acceptable during ambient temperature extremes. Reduced CO2 removal could be accepted during temperature extremes, so performance estimates that were used to develop monthly average net output for input to the economic analysis were developed without chillers. To maintain compatibility with the economic analysis, the chillers and appurtenances were removed from the capital cost estimates. Weather analysis from a 2002 Energy Commission comparison of alternate cooling technologies for California power plants indicates that ambient temperatures that would require the use of chillers for CCS cooling would occur for only a few hundred hours a year for locations in the Bay area. The need for supplemental cooling or chillers for the carbon capture system are highly dependent on location. While chillers for the carbon capture system can be avoided for Bay Area sites such as the one considered in this study, other sites could require such provisions.

## 3.2.9 Capacity Factor

Gateway's capacity factor for the year 2011 was approximately 50 percent based on Ventyx model data for this facility. Future capacity factors will depend upon a number of factors including load growth, retirement decisions, generation expansion plans (including renewable additions), as well as future natural gas and CO2 allowance prices. CB&I conducted dispatch modeling of the Western Electricity Coordinating Council (WECC) to project future capacity factors at Gateway. The dispatch modeling included the projected CO2 allowance prices associated with the California cap and trade program in the dispatch price of all generating assets in WECC modeling domain<sup>12</sup>. The application of CO2 allowance prices in the dispatch price of non-California generating units was implemented as a means of addressing the requirement of AB 32 to prevent "leakage" (reduction of in-State emissions with parallel increase in emissions out of State). While this modeling approach may not exactly match the mechanisms California will ultimately utilize to address emissions from imported electricity, CB&I believes this approach to be reasonable and more representative of how AB 32 will affect generation in California than only applying the CO2 pricing to the California generating assets.

If CCS is installed at Gateway, the dispatch cost for this facility would change relative to the dispatch cost of similar facilities without CCS. Fuel cost on a \$/MWh basis would increase due to the higher net plant heat rate associated with the CCS retrofit. Variable O&M costs on a

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<sup>&</sup>lt;sup>12</sup> Initial modeling that applied CO2 allowance prices in the dispatch cost to only California generating plants resulted in large increases of imported power from other WECC facilities.

\$/MWh basis would increase due to heat rate impacts and the incremental variable costs associated with the CCS<sup>13</sup>.

Based on the preliminary dispatch modeling, it is recommended that a base case capacity factor of 65 percent be used in the life cycle cost model simulations of the retrofit of CCS at Gateway. Due to the many variables that can impact future capacity factors and the uncertainties associated with long term projections of these key variables, it is suggested that the life cycle cost model evaluate a range of capacity factors from 30 percent to 90 percent. Additionally, as a policy measure to encourage CCS, a must-run designation could be assigned to some of the first units with CCS, for at least some of the remaining life. Such a policy is expected to require funding to support operation of facilities at capacity factors that exceed their economic dispatch.

## 3.2.10 Availability

After consideration of the assumptions used in the planned outage rate, forced outage rate and percent of derate for each technology it was determined that the availability for Gateway with a carbon capture system would be not change with a carbon capture system. It was assumed that the planned maintenance for the carbon capture system could be performed during the interval of time for planned outages that was allocated for the power plant and the forced outage rate and percent of derate would not increase since the carbon capture system is at least as reliable as the NGCC plant. It is also assumed that the regulations will allow for short term operation of the plant while bypassing the carbon capture system in the event there is a forced outage that limits the carbon capture system operation. Since Gateway specific data was not available, CB&I's assumptions were based on a typical NGCC plant of design similar to Gateway and a long-term availability of 92.85 percent based on a 4.55 percent planned outage rate, 1.47 percent forced outage rate, and 1 percent derate.

## 3.2.11 Required Equipment and Space

The new CO2 capture equipment will be located to the west of the existing Gateway stacks and north of the existing switchyard equipment on the existing Contra Costa plant site. A conceptual site plan arrangement showing the locations and physical sizes of the new carbon capture equipment and ancillaries relative to the existing Gateway site is shown in Figure 4.

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<sup>&</sup>lt;sup>13</sup> The operating and maintenance costs of the CO2 pipeline and the CO2 sequestration operations have been included as fixed O&M category and therefore do not affect the dispatch price.

0 4)-N 38+23.5 H E 41+43.792 H UNIT 8 N 36+89.5 E 41+43.792 0100 F N 3500 68088088 CO2 CAPTURE EQUIPMENT LEGEND DESCRIPTION FLUE GAS COOLER BOOSTER FAN CO2 ABSORBER SOLVENT HEAT EXCHANGERS DESORBER/STRIPPER 6 CO2 COOLER REFLUX VESSEL CO2 CLEANUP & DEHYDRATION 9 REBOILER COMPRESSORS PUMPS BOP EQUIPMENT 14) CONTROL BLDG. TWANSTORWERS (15) SOLVENT STORAGE TANK MAKEUP WATER TANK GATEWAY GENERATING STATION COOLERS STACKS-EXIST. CO2 CAPTURE EQUIPMENT CONCEPTUAL ARRANGEMENT FOR RETROFIT CASE (9) TRANSFORMER FRANS-CRMERS NEW STACK

Figure 4: CO2 Capture Equipment Conceptual Arrangement for Retrofit Case

## 3.2.12 Modifications to Water and Waste Water

With dry cooling, demineralized water makeup to the CCS system is not required at the average ambient conditions analyzed. An allowance of 5 gpm on an average basis is recommended to account for different ambient conditions. Waste water blowdown is estimated at 316 gpm. The ability of the existing plant to accommodate these quantities will need to be determined when plant specific data is available. If needed, additional demineralizer capacity can be provided by a contracted package unit with off-site regeneration. The cost of demineralized water from such a unit has been included in the O&M cost estimate.

The CCS technology suppliers have indicated that the waste water blowdown is not expected to be considered hazardous and thus can be discharged to a municipal sewer if properly treated. In the absence of more specific information from Gateway, the cost of waste water disposal has been included in the O&M cost estimate based on treatment for disposal to an industrial sewer and Contra Costa Sanitary District industrial rates.

#### 3.2.13 Flue Gas Pre Treatment

The technology suppliers have indicated that the only pretreatment of the flue gas is to reduce the temperature from the typical NGCC HRSG exit gas temperature of around 200°F to around 100°F, both depending on the exact NGCC plant and CCS operating conditions. The diagrams, descriptions and estimates provided indicate that the flue gas cooling equipment is typically included as part of the CCS package. The cooling equipment will also capture the water in the flue gas from CT combustion air, natural gas combustion, and any water additions such as CT inlet cooling and/or water injection.

The only chemical concern mentioned is that sulfur in the flue gas would react with the amine solvent solution to produce solid compounds that would become suspended in the solvent solution and interfere with processing. In a typical, modern, NGCC plant, a similar concern exists for the ammonia based NOX reduction systems, SCR with ammonia reagent, and strict limits are imposed on fuel sulfur content. Further, sulfur in the CT exhaust will be reacted with the ammonia in the SCR system, resulting in negligible amounts in the HRSG flue gas reaching the CCS system.

## 3.2.14 Impact on Operations

The primary factors affecting plant operating flexibility are:

- Startup time HRSG drum heat up rate and ST heat up rate.
- Load ramp rate ST temperature differentials.
- Turndown CT minimum load.

The carbon capture system will not affect any of the factors listed above.

## 3.2.15 Operations & Maintenance Staffing

CCS operations staffing costs are based on operating labor of three workers on site per shift for NGCC. These include a control operator, a yard operator and a roving operator that can serve

as relief for either the control or yard operator. Operator cost is based on typical utility practice of five shifts per day and an average wage rate of \$38.46/hour.

Maintenance staffing costs are based on maintenance labor of six workers on a single day shift. These include a journeyman and a helper for each major maintenance craft. Maintenance labor cost is based on an average wage rate of \$31.25/hour.

Supervision and overhead costs are added to the above wage rates based on utility data from previous CB&I studies.

## 3.2.16 Environmental

Environmental concerns can only be discussed in a general way until the host facility for retrofitting CO2 capture technology is identified and a site-specific evaluation of the selected CO2 capture technology is completed. Preliminary estimates of changes in a facility's wastewater discharges, air emissions, delivery and storage of new materials, and storage and disposal of new solid and liquid waste streams are typically prepared prior to developing an environmental permitting plan. At this point, the differences between the various capture technologies are not expected to result in material differences in the need to modify existing environmental permits or to obtain new environmental permits. CB&I does not anticipate that required modification of existing permits, plans and reports at existing NGCC facilities due to the retrofit of the CO2 capture technology will present a significant barrier to developing successful CCS projects.

Existing NGCC facilities with wet cooling are likely to have more flexibility for integrating wastewater streams associated with the CO2 capture technologies than a facility using an ACC for plant heat rejection.

The major environmental permits and plans, which could be impacted by the retrofit of CO2 capture technologies at a NGCC facility include the air permits (Authority to Construct and Permit to Operate) and NPDES wastewater discharge permit. It is expected that there would be modifications to a number of plans and reports held by the facility to account for the additional equipment added to the site and the receipt and storage of new chemicals associated with the CO2 capture system. The CCS project would also result in new COC issued by the Energy Commission.

The retrofit CO2 capture technologies will modify the flue gas characteristics that exit the existing stacks at a NGCC facility. These changes could require dispersion modeling of the existing stack(s), or new stack(s) if included in the detailed design. In addition to potential changes in criteria pollutants or hazardous air pollutants, flue gas dispersion characteristics affecting plume buoyancy will likely be modified by the addition of the CO2 capture technology and will need to be considered in any air dispersion modeling that is required as part of the CO2 capture technology retrofit.

The current concept of providing thermal energy to the CO2 capture technologies involves extracting steam from the existing NGCC power plant steam cycle. It is also assumed that there will not be increased fuel flows to either the existing CTs or duct burners (if included in the

existing plant design). However, if further technical evaluations determine that new sources of steam supply will be required (e.g., new auxiliary steam boilers), then the additional air emissions from this new source would need to be quantified and evaluated in terms of potential modifications to the existing air permits.

The retrofit of CO2 capture technologies will generate low volume wastewaters as part of the CO2 capture process. These wastewaters may be treated such that there is "zero liquid discharge" associated with the retrofit CO2 capture technology. This could involve treatment of the CO2 capture technology wastewater streams such that the treated wastewater can be used by the NGCC facility. If a new liquid wastewater discharge from the NGCC site results from the CO2 capture technology, modifications to the facilities NPDES permit or industrial sewer discharge permit may be required.

It is possible that an existing NGCC facility may also need to modify or amend certain plans (e.g., Emergency Response Plans, Spill Prevention Control and Countermeasures Plans, Occupation Safety and Health Programs), due to the receipt and storage of new chemicals onsite associated with the CO2 capture technology process.

The impact of the carbon capture system process solvents on an existing facility such as Gateway, on operations, the safety preparedness measures and the environmental controls will depend on the exact chemicals used. The solvents/reagents do not have material safety data sheets, because of the proprietary information in their formulation. However, the compound generally referred to in their formulation, MEA, is a common industrial product. MEA is similar to ammonia, which is used at most NGCC sites. Based on the characteristics common between CO2 capture solvents and products typically used at NGCC sites, there should not be any major changes in the safety preparedness measures, environmental control/assurance, operations, or material handling and disposal procedures. It is assumed that the impact of solvent use and disposal is similar to ammonia.

## 3.2.17 Carbon Emissions

The CO2 emissions were calculated for Gateway with and without a carbon capture system. The CO2 emissions are based on a carbon capture system that is designed for 90 percent CO2 removal typical gas-fired flue gas composition; and flue gas quantities calculated by the Thermoflex heat balance model. Table 8 summarizes the carbon emissions for Gateway, with and without carbon capture.

Table 8: Estimated CO2 Emissions at Gateway

	Without CCS	Advanced Amine CCS
CO <sub>2</sub> Emissions (lb/hr)	461,500	46,150

## 3.3 Cost Analysis

A cost analysis was performed to compare the cost for Gateway with and without a carbon capture system. The Model that was described in the section, "Development of the Engineering Options Analysis Procedure was used; the cost components of the Model consist of the following:

- Capital costs to retrofit Gateway with a carbon capture system.
- Capital costs for a CO2 transportation pipeline and injection system. In the Gateway scenario wellhead pumps are considered but a booster pump along the route is not assumed necessary.
- Incremental fixed and variable O&M cost for the carbon capture system.
- Incremental fixed and variable O&M cost for the CO2 transportation pipeline and injection system.
- CO2 emissions penalty.
- Replacement power.

## 3.3.1 Capital Cost

Capital cost estimates were prepared to retrofit Gateway with an advanced amine technology carbon capture system, CO2 compressors, and the CO2 transportation pipeline and injection system. The carbon capture and compressor system EPC cost estimate is based on publicly available cost information, information assembled from the carbon capture system and compressor suppliers, and applicable experience based costs derived by the CB&I estimating group. The construction period is a typical expected length of time to implement the carbon capture and compression system based on CB&I's recent construction experience with large scale air quality control systems, which include flue gas desulfurization and selective catalytic reduction flue gas stream modifications.

The EPC costs for carbon capture can be broken down into four general categories shown in Table 9:

Table 9: EPC Costs to Retrofit Carbon Capture (\$ Million)

	Cost (\$Million)	Percentage
Carbon Capture System	\$548	65.8%
Compression	\$78	9.4%
Cooling	\$76	9.1%
Balance of Plant	\$131	15.8%
Total Carbon Capture EPC Cost	\$833	100%

The bulk of the cost is from the carbon capture system. Compression includes compressors, dryers, and fans. Cooling includes cooling system area and chiller piping. These costs include direct materials cost, direct labor cost, and indirects (distributables, home office services, start-up support, transportation, etc.).

Table 10 summarizes the capital costs for retrofitting Gateway with a CO2 capture system.

Table 10: Capital Costs to Retrofit Carbon Capture (\$ Million)

	Advanced Amine CCS
Carbon Capture EPC Cost (2012\$ overnight cost)	\$833
CO <sub>2</sub> Injection System EPC Cost	\$23
CO <sub>2</sub> Transportation EPC Cost	\$5.3
Total EPC Cost	\$861
Owner's Cost	\$15
Interest During Construction	\$82
Inflation and Escalation	\$43
Project Contingency	\$86
Total Capital Cost	\$1,088

Source: CB&I

The capital cost estimate for retrofitting Gateway with CCS took into account the following key components:

- Carbon Capture System
  - o Cooling System
  - o Compressors
  - o Power Supply System
  - o CCS Power Supply at the Power Island
  - o Relocation of Switchyard Components to Accommodate the New CCS Equipment
  - o Power Supply Cost Basis

- CO2 Transportation Pipeline
  - o Pipeline Routing
  - o Back Pressure Caused by Failure of Compression
  - o Isolation of Pipeline Segments in the Case of a Leak
  - o Depressurization of Discreet Pipeline Segments
  - o Emergency Shutdown Valve
  - o Basis of Cost
  - o Power Supply
  - o Shipping
  - o Labor and Equipment
  - o Civil Work
  - o Pre Installation Labor Costs
- CO2 Injection System
  - o Pre-operation Geological Assessment and Preparation of the Geologic Model
  - o Investigation Drilling and Testing of the Target Horizon by the First CO2 Injection Well
  - o Installation of Two Additional CO2 Injection Wells
  - o Installation of Six CO2 Monitoring Wells
  - o Monitoring during the Operation of CO2 Injection System
  - o CO2 Monitoring During the Post Closure Period

## 3.3.2 Operation & Maintenance Costs

The O&M costs consist of fixed and variable O&M cost components. The O&M costs include the costs needed to operate and maintain Gateway, both with and without a CO2 capture system. The O&M costs do not include fuel costs, replacement power costs, or carbon penalty costs (also referred to as carbon emissions allowance cost). The O&M costs do, however, include ongoing capital improvements or replacements associated with the installed systems that were not included in the upfront capital costs. The O&M costs are based on information from typical NGCC plants and are not specific to Gateway since actual values from Gateway were not available.

## 3.3.2.1 Fixed Operation & Maintenance

The fixed O&M cost is the annual cost to capture carbon that does not vary depending on the amount of electricity production. The fixed O&M costs include any ongoing capital

improvements or replacements associated with the installed systems that were not included in the upfront capital costs and any costs resulting from changes in operations, safety measures or environmental control requirements, including additional staffing and permanent emergency response equipment. See the discussion in Section 3.2.15 on the impact of the CCS on staffing levels.

Periodic maintenance is assumed to be subcontracted and is estimated based on the 6 percent of CCS system cost per previous CB&I studies.

Major maintenance and capital improvement cost is based on 14 percent of CCS system cost per previous CB&I studies, adjusted for the maturity of the CCS technology.

An important aspect in the operation of the injection well field is the observation of the gas pressures at the injection wells and the monitoring wells. The observation of increasing gas pressures in the monitoring wells are signs that the CO2 plume is migrating toward the monitoring well. The progress of the CO2 plume will be tracked and documented in accordance with pre-injection model projections. Significant deviations from the pre-injection modeling projections could be indications of differences in the assumed and actual geologic conditions of the reservoir. However, a buildup of inject pressures at the injection wells could be an indication of plugging of the injection interval of the well. It is assumed that routine well redevelopment or work over operations will be required at each injection well during the operational phase of the CCS program.

The length of time between initial startup of injection and need for redevelopment is difficult to determine at this time. However, it is prudent to assume that injection well redevelopment will be required on five to ten year intervals during the course of the injection period. The length of the intervals between redevelopments will be controlled by the interaction of the injected gas products and the reservoir materials, fluids, and gases, which could cause plugging of the injection interval of the well. Redevelopment will require the mobilization of a work over rig to investigate and remediate the well plugging. Redevelopment of injection and production wells in a common practice in the oil and gas industry, and common investigation and remediation methods will be utilized for the CCS program.

For cost estimating purposes, it is assumed that redevelopment activities could take place every five years for each of the three injection wells throughout the course of the CCS program. The assumed per cost is \$500,000 for each well redevelopment. This estimate assumes that the injection well can be brought back to pre-injection conditions without the use of aggressive activities, such as, re-drilling of the well.

## 3.3.2.2 Variable Operation & Maintenance

The variable O&M includes the O&M costs that vary depending on how much the plant is operated and the amount of carbon that is captured. The variable O&M of carbon capture system is expressed as a cost per year divided by the annual amount of electricity production. The variable O&M for the carbon capture system includes the cost of solvents/reagents, makeup water, solvent/reagent disposal, and waste water disposal. Note that variable O&M does not include the power required to operate the compressors that are part of the plant carbon capture

system as these loads are internal to the plant and are accounted for in the replacement power category.

The following base rates have been used from the sources indicated

- Demineralized water makeup = \$3.10/100 gallons: previous CB&I studies.
- Solvent/reagent makeup = \$7.00/lb: 2X commercial MEA cost.
- Waste water (sewer) disposal = \$3.44/100 cubic feet: Central Contra Costa Sanitary District web site.
- Raw (potable) water makeup= \$4.76/1000 gallons plus \$1.48/day surcharges: Contra Costa Water District web site.

## 3.3.2.3 Additional Operations and Maintenance Cost

Included in the incremental fixed and variable O&M cost for the CCS is the cost to maintain the CCS, monitor the CO2 extraction, transportation and storage systems during the operation of plant. The additional O&M cost for Gateway that has been retrofitted with a CO2 capture system is summarized in Table 11 below.

Table 11: O&M Costs for Carbon Capture Retrofit (2012\$)

Fixed O&M Costs (\$ per kW-yr) <sup>1</sup>	Advanced Amine Technology
Fixed O&M Cost for CCS	6.4
CO <sub>2</sub> Transportation and Injection Fixed O&M Cost	3.5
Total Fixed O&M Cost for CCS	9.9
Variable O&M Cost (\$ per MWh) <sup>1</sup>	
Variable O&M Cost for CCS	3.7
CO <sub>2</sub> Transportation and Injection Variable O&M Cost	-
Total Variable O&M Cost for CCS	3.7
<sup>1</sup> Based on nominal 454 MW average net rating	

Source: CB&I

## 3.3.3 Replacement Power

Replacement power cost is the cost of power that would need to be purchased in order to make up for the reduction in electricity production after the carbon capture system retrofit. Beginning with a constant fuel input, replacement power accounts for the decrease in power output from cycle steam use, and the power consumption of the carbon capture system. For the base case

the first year of replacement power cost is assumed to be representative of the California average grid for industrial end use: \$98/MWh with 1% real escalation and 0.26 tons CO2 emitted per MWh. Sensitivity cases include replacement power from a new NGCC (\$88/MWh with 1 percent real escalation, 0.45 tons CO2 emitted per MWh) and from wind (\$100/MWh with 1 percent real escalation, 0 tons CO2 emitted per MWh). These costs were developed based on the base economic assumptions in the model and Energy Information Administration (EIA) cost data for California.

#### 3.3.4 Revenue

Typically levelized cost comparisons only consider direct electrical energy costs because electricity is the product and the only source of revenue. For a levelized cost comparison involving plants that have other sources of revenue besides electricity, credits or reductions are given for the other sources of revenue. This Model is set up to account for a reduction in ancillary services revenue due to a lower capacity and less generation or to include an additional revenue source from CO2 sales for enhanced gas recovery (EGR) or EOR. The base case assumes no CO2 sales, but in the sensitivity cases where CO2 sales are assumed, the CO2 transportation and injection capital and O&M costs are not included as they are assumed to be included in the CO2 sales agreements with the point of sale at the plant boundary.

## 3.3.5 Economic and Price Inputs

The economic inputs include: inflation, capital and O&M escalation, discount rate, and the capital recovery rate. Refer to the section on "Development of the Retrofit Engineering Options Analysis Procedure" for more detailed discussion of these inputs. The inputs are summarized in Table 12.

**Table 12: Inflation and Escalation Assumptions** 

General inflation	1.7%/year
Real capital cost escalation	0%/year
Real electricity/steam escalation	1%/year
Real O&M cost escalation	0%/year
Real CO <sub>2</sub> penalty price escalation	7%/year
Real CO <sub>2</sub> sales escalation	1.2%/year
Real ancillary services revenue escalation	1%/year
Real discount rate	5%

Source: 2012 EIA AEO, Ventyx model, USDA Economic Research Service, CB&I

The price inputs include natural gas price, natural gas price escalation, CO2 emissions penalty price, and CO2 emissions penalty price escalation. The CO2 emissions penalty price is assumed to be \$18.40/ton CO2 in the first year of operation with 7% escalation thereafter, which is consistent on a lifecycle average basis with the CO2 penalty assumption used in the Ventyx model. Refer to Task 3.1 Development of the Retrofit Engineering Options Analysis Procedure for more detailed discussion of these inputs. The natural gas price assumption and its basis are summarized in Table 13 below.

Table 13: Natural Gas Price and Escalation Rate

	Initial Price (at COD in 2016, nominal \$)	Real Escalation Rate	Basis
Natural Gas	\$4.56/MMBtu	2.9%/year	2012 EIA AEO

Source: 2012 EIA AEO

## 3.3.6 CCS Retrofit Base Case Results

The two key figures of merit included in the results are the incremental levelized cost of production (COP) in \$/MWh and the cost per avoided CO2 emissions in \$/ton CO2. The incremental levelized COP accounts for the additional costs and revenues that are associated with a CCS retrofit. Both capital and O&M costs are included. Replacement power is accounted for separately and shows the effect of reduced performance, including capacity derates, increased internal loads, and capacity factor reductions. Because the replacement power cost and power production are included, the original power production is used when calculating the levelized COP. The cost per avoided CO2 emissions accounts for the levelized cost and also the amount of CO2 emissions that are avoided by installing the retrofit. The avoided CO2 emissions account for the CO2 captured in the CCS system and the CO2 emissions associated with the replacement power.

The incremental levelized COP is \$43/MWh and the cost per avoided CO2 emissions is \$123/ton CO2. Figure 5 and Figure 6 below show the breakdown of the incremental levelized COP and cost per avoided CO2 emissions.

Ancillary Services
Revenue Reduction

O&M

Replacement Power

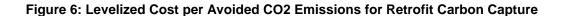
Capital Cost Recovery

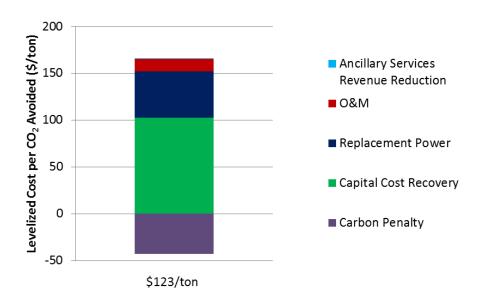
Carbon Penalty

\$43/MWh

Figure 5: Levelized COP for Retrofit Carbon Capture

Source: CB&I





Capital costs are the most substantial component of the levelized cost economics, followed by replacement power. Avoided carbon penalty costs and O&M are less significant contributors and ancillary services revenue has virtually no effect. CO2 sales are not included in the base case but one can see the moderate effect on the overall economics in the sensitivities in the next section. The relatively high values for both of these metrics are due primarily to the large effect that dry cooling has on the performance.

## 3.3.7 Sensitivity Analysis for Retrofit Cases

#### 3.3.7.1 Overview

Due to uncertainties necessarily inherent in relying on assumptions and projections, it should be anticipated that actual results would differ based on the assumptions used. In order to demonstrate the impact of certain circumstances on the study results, CB&I developed sensitivity analyses to key assumptions. It should be noted that other examples could have been considered, and those presented are not intended to reflect the full extent of possible impacts on the study.

As part of the technical evaluation of the retrofit options, CB&I determined that there are many design sensitivity analyses which could be performed such as: enhanced auxiliary boiler or duct firing capacity to meet solvent regeneration steam requirements, ASU oxygen purity, reduced CO2 capture efficiency, part-load operation, and CO2 capture system bypass. Rather than conducting sensitivity analyses to determine the optimal design, CB&I considered all these factors and developed the best case design based on the technology that is available today. The sensitivity analyses instead focused on key input parameters that impact the lifecycle economics: capacity factor, CCS equipment cost, CCS capacity impact, CO2 emissions penalty price, CO2 sales revenue, discount rate, fuel price, and replacement power.

#### 3.3.7.2 Sensitivity Cases

CB&I has incorporated in the Model several sensitivity analyses by varying the following specific key input parameters:

## Capacity factor

The capacity factor is influenced by the forced outage rate, planned outage rate, and the dispatch. Because of the uncertainties in projected outage rates and the future California power market, a sensitivity range on capacity factor of 30 percent to 90 percent is assumed. Because of the uncertainties surrounding the dispatch, the sensitivity range is intended to serve as a parametric range and also is intended to include the potential effects outside the power market such as a policy decision to designate a carbon capture plant as "must run" for at least part of its life.

## • CCS equipment capital cost

o The accuracy of the CCS capital cost estimate is contingent on the information that was used to develop the estimate as well as the market condition at the time of implementation for EPC contractors, equipment and bulk material. The CCS

estimate is based on information provided by the vendors and CB&I's internal database of costs. It is not based on a vendor quote and therefore there is a potential for a wide range of inaccuracy in the estimate. The sensitivity varied the CCS capital cost estimate by -30 percent and +50 percent.

## • CCS capacity impact

o The CCS provides an additional auxiliary load on the plant compared to a plant that does not have a CCS. That auxiliary load can vary and therefore a sensitivity was performed to estimate the impact on the COP. A sensitivity range of ±10 MW was used.

## CO2 emissions penalty price

The future CO2 emissions penalty price will be influenced by a mix of existing and future state and federal regulations on GHG emissions, which could include cap and trade CO2 emission markets, CO2 taxes, or caps on CO2 emissions through renewable/clean energy standards or other means. The CO2 emissions penalty price resulting from these regulations will likely be affected by the cost of other technology alternatives that can be used to mitigate CO2 emissions. A low sensitivity case of \$10.90/ton corresponds to the equivalent price for the CARB cap and trade market floor and the high sensitivity case of \$25.90/ton corresponds to a price above the nominal price that results in a symmetric sensitivity around the nominal price taken from the Ventyx model. Because of the uncertainties surrounding this price, the sensitivity range is intended to serve as a parametric range.

#### CO2 sales revenue

The CO2 sales revenue tracks the price of oil and with wide fluctuations in oil prices, there is a potential for the CO2 sales revenue to fluctuate as well. The impact of the CO2 sales price on the COP is tested by varying the CO2 sales price in increments of \$5/ton CO2 around the base case price as a parametric analysis. A ±\$5/ton CO2 range is roughly consistent with a sensitivity range of ±33 percent, which is what EIA projects for oil prices (and which the EOR CO2 price is tied to).

#### Discount rate

The discount rate will vary depending on the risk tolerance and value that the project owner places on money invested in the project over its life. In the power industry, projects can generally be characterized as merchant, IOU, and public owned utility (POU), with merchant projects having the highest discount rate and public owned utility projects having the lowest discount rate. The discount rate base case is intended to be generally representative of rates for an IOU project at a real 5 percent. The low sensitivity case is intended to be generally representative of rates for a POU project at a real 3% and the high sensitivity case

is intended to be generally representative of rates for a merchant project at a real 6 percent.

## • Fuel price

Fuel prices are important sensitivity cases since the cost of fuel has fluctuated widely over the last few years. The base case fuel prices are based on 2012 EIA Annual Energy Outlook (AEO) reference case prices. The low fuel price sensitivity cases are based on the 2012 EIA AEO low coal price and high shale recovery case prices and the high fuel price sensitivity cases are based on the 2012 EIA AEO high coal price and low shale recovery case prices.

## Replacement power

o Replacement power cost is dependent on the power market and many factors affect the price of power, therefore the following sensitivity cases were included as replacement power from a new NGCC (\$88/MWh with 1 percent real escalation, 0.45 tons CO2 emitted per MWh) and from wind (\$100/MWh with 1 percent real escalation, 0 tons CO2 emitted per MWh).

The suggested sensitivity ranges are summarized in Table 14.

**Table 14: Sensitivity Parameters and Ranges** 

Sensitivity Parameter	Sensitivity Range			
Capacity factor (%)	30%-90%			
CO <sub>2</sub> Emissions Penalty (\$/ton CO <sub>2</sub> )	\$18.40 ±\$7.50			
CO <sub>2</sub> Sales Revenue (\$/ton CO <sub>2</sub> )	\$0, \$10 ±\$5 (CO <sub>2</sub> transportation and injection costs are included only in the base case which assumes no CO <sub>2</sub> sales)			
CCS Equipment Capital Cost (% of base)	-30% & +50% of base CCS equipment cost			
CCS System Capacity Impact (MW reduction)	±10 MW			
Discount Rate (%)	3% - 6%			
Natural Gas (\$/MMBtu)	\$4.56 ±25%			
Replacement Power Cost (\$/MWh) and CO <sub>2</sub> Emissions (tons CO <sub>2</sub> per MWh)	NGCC: \$88/MWh, 0.45 tons/MWh California Average Grid: \$98/MWh, 0.26 tons/MWh Wind: \$100/MWh, 0 tons/MWh			

## **Sensitivity Results**

The sensitivity results are shown in Table 15 below:

**Table 15: Sensitivity Results for Retrofit Carbon Capture** 

		Capacity Factor	CO <sub>2</sub> Penalty	CO <sub>2</sub> Sales Price	CCS Equipment Capital Cost	CCS Performance Impact	Discount Rate	Replacement Power Cost and CO <sub>2</sub> Emissions
Parameter	Base Case	65%	\$18.40/ton	No sales	Base Cost	Base Performance	5%	CA Grid Average
	Upper Sensitivity	90%	\$25.90/ton	\$15/ton	+50%	+10 MW	6%	NGCC
	Lower Sensitivity	30%	\$10.90/ton	\$5/ton	-30%	-10 MW	3%	Wind
	Base Case				<u> </u>	·		\$44/MWh
Results								\$124/ton
	Upper Sensitivity	\$33/MWh	\$37/MWh	\$32/MWh	\$61/MWh	\$46/MWh	\$49/MWh	\$42/MWh
		\$93/ton	\$105/ton	\$90/ton	\$172/ton	\$131/ton	\$138/ton	\$128/ton
	Lower Sensitivity	\$87/MWh	\$50/MWh	\$39/MWh	\$33/MWh	\$41/MWh	\$34/MWh	\$44/MWh
		\$246/ton	\$140/ton	\$109/ton	\$94/ton	\$115/ton	\$95/ton	\$112/ton

The three parameters that have the largest sensitivity ranges are capacity factor, CCS equipment cost, and discount rate. The results are shown in Figure 7 and Figure 8 below. The most economic cases will be dispatched as much as possible and thus have a high capacity factor; will have the lowest CCS equipment costs and thus the lowest capital costs; and will have the most favorable financing and thus the lowest discount rate.

Figure 7: Sensitivity of COP to Capacity Factor, CCS Cost and Discount Rate (Retrofit Carbon Capture)

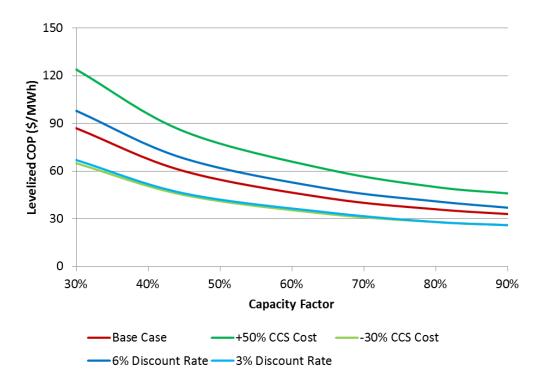
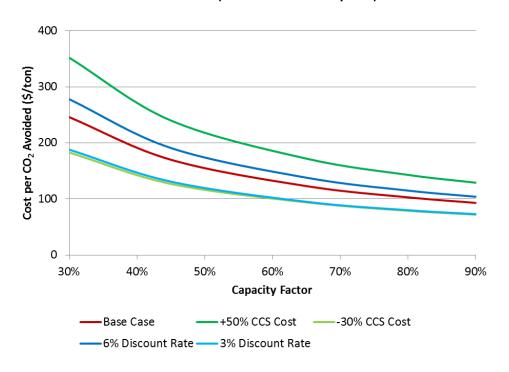


Figure 8: Sensitivity of Cost of Avoided CO2 Emissions to Capacity Factor, CCS Cost and Discount Rate (Retrofit Carbon Capture)



In addition, parametric studies were also conducted for capacity factor and CO2 sales for EOR. The results are shown in the Figure 9 and Figure 10 below.

Figure 9: Sensitivity of Costs to Capacity Factor for Retrofit Carbon Capture

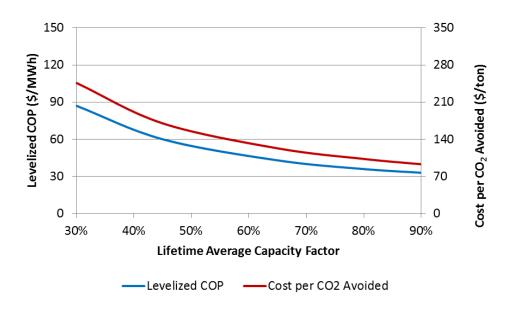
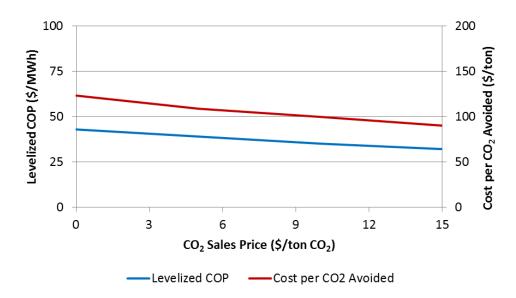


Figure 10: Sensitivity of Costs to CO2 Sales Price for EOR (Retrofit Carbon Capture)



# **CHAPTER 4:**

# Preliminary Engineering Design and Analysis for New Build Ngcc Plant With Co2 Capture System

#### 4.1 Overview

The New Build application is to incorporate NGCC and CCS configurations based on designs that could be commissioned by 2025 with CCS fully integrated in the original design and construction of the NGCC facility. The plant configuration incorporates design modifications that are intended to provide an optimized integration of the NGCC power block and the CO2 capture and compression facilities. This Study uses the CPV Vaca as the basis to evaluate the cost and performance of a New Build NGCC plant with integrated CO2 capture and geologic sequestration. This plant is proposed as a 660 MW natural gas-fired power plant near Vacaville, California by CPV Vacaville LLC and is currently in review by the Energy Commission Siting Division. The public record provided in the CPV Vaca Application for Certification (AFC), and other documents prepared for the siting proceedings, verify that this a commercially viable site with access to gas supply, electric transmission, water, plot space, and other resources required for a successful project. Analysis by CB&I and LLNL, using reports and data from the California Geological Survey, California Division of Oil and Gas, has identified a candidate site for geologic storage that is expected to have the necessary capacity, along with routing options for a CO2 transport pipeline from the CPV Vaca site to the storage site.

In consideration of the expected advances in CO2 Capture Technologies and the efficiencies of optimized integration into the power generation cycle, the New Build analysis assumes a 30 percent decrease in regeneration steam requirements and a 20 percent decrease in electric power requirements over the technologies assumed for the retrofit analysis. The technology supplier responses indicate that a further improvement of approximately 5 percent could be realized through FGR although details are not available.

# 4.2 Preliminary Engineering Design For New Build NGCC Plant

In the absence of specific plant data for CPV Vaca, a reference New Build plant was developed from the CB&I database. This reference plant is a nominal 660 MW, GE Frame 7 FA-05 based, 2x2x1 combined cycle arrangement; which is a similar configuration to CPV Vaca and other proposed plants. Using the Thermoflex heat balance software, the initial heat balance was revised for the ambient conditions in the Vacaville, California area so as to be more representative of the site plant selected. The annual average ambient conditions are used as well as all cooling is by dry systems. The selection of a GE system does not exclude the use of other power block suppliers from a new build opportunity.

#### 4.2.1 Carbon Capture System

#### 4.2.1.1 Overview

For study purposes, this analysis has been limited to those technologies that are compatible with the common 2x2x1 combined cycle arrangement using CT designs that are currently available or are expected to be available for commercial operation by 2025. Special cases are discussed separately. All technologies are analyzed based on 90 percent CO2 capture design to allow turndown during high temperature and high load conditions, which are offset by operation at 90 percent during favorable conditions.

The diverse approaches studied by technology provider RD&D organizations, academic researchers, and others include the following categories.

- Some approaches modify the conventional configuration of a combined cycle power plant. These include:
  - o Capture of CO2 from hot combustion products prior to expansion in a CT.
  - o Capture of CO2 from a molten carbonate fuel cell using flue gas in the place of air and CO2 recycle on the of a molten carbonate fuel cell.
- Post combustion capture approaches include use of:
  - o Liquid chemical or physical sorbents (solvents) in a process configuration common to many chemical industry applications.
  - o Solid sorbents in a circulating fluidized bed or alternating fixed-bed configuration.
  - o Membrane separation.
  - o Cryogenic capture at near-atmospheric pressure (anti-sublimation or "frosting").
  - o Pressurized cryogenic capture (partial condensation of compressed flue gas, with distillation as needed).

For this study, requests for information were sent to over 100 organizations. The technologies represented by the responsive organizations were evaluated for applicability to a new build NGCC power plant. These included:

- Amine solvent combustion capture
- Non-amine solvent post combustion capture
- Membrane post combustion capture
  - o Membrane as a contact medium for solvent capture
  - o Membrane itself as a capture process
- Fuel cell post-combustion capture

- Oxy-fuel pre-combustion capture
- Methane reforming pre combustion capture

A number of studies assume that exhaust gas injection (EGI) will be used to reduce the size of the CO2 absorber in a pulverized coal combustion (PCC) application, thereby reducing cost and improving efficiency. EGI is also a possibility for NGCC as several major CT suppliers have published studies suggesting that dry low NOx (DLN) combustors can handle up to 40% EGI without significant problems.

#### 4.2.1.2 NGCC with Post-Combustion Capture

To enable the capture of CO2 from the CT flue gas streams, the HRSG exhaust is ducted to the CCS system. Ductwork and damper configuration are provided to allow by-pass of the CO2 capture plant and the HRSG exhaust to be discharged directly to atmosphere to allow maintenance on the CCS system while the power plant remains in operation. A schematic of a typical amine based chemical CCS process from an IPCC Special Report on Carbon Dioxide Capture and Storage, Kelly Thambimuthu, lead author is shown in Figure 11 below:

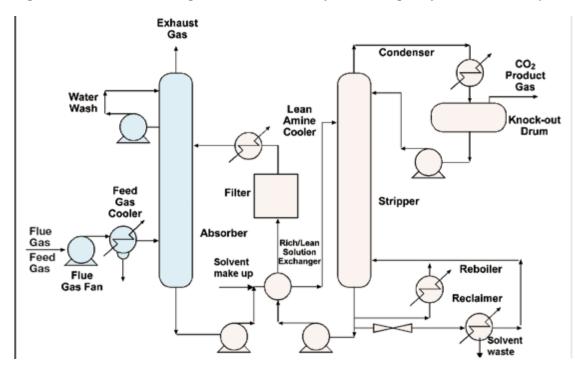


Figure 11: Process flow diagram for CO2 recovery from flue gas by chemical absorption

Source: IPCC Special Report on Carbon dioxide Capture and Storage

Booster fans are provided to overcome the additional pressure drop in the flue gas ductwork associated with the CO2 process equipment. Once inside the absorber, the flue gas stream is mixed (scrubbed) with a special solvent which subsequently releases CO2 from the flue gas and then it is absorbed into the liquid solvent. The absorber vessel is located adjacent to the flue gas cooler to help reduce the length of ductwork runs. From the absorber, the flue gas then exists to atmosphere.

CO2that has reacted and combined with the liquid solvent inside the absorber flows from the bottom of the absorber vessel along with the solvent through a heat exchanger that heats up the CO2 "rich" mixture before it enters a large stripping vessel. On-site solvent storage and makeup systems are included in the design to ensure a continuous source of solvent is always available for the CO2 capture process.

Inside the stripping vessel, CO2 is released from the solvent mixture by the addition of heat. Heat is supplied to the stripper vessel from a "reboiler" that uses low pressure steam supplied from the main generating plant. Condensate from the CO2 process is continually collected and returned to a separate condensate storage tank for reuse.

The solvent may be liquid or solid composed of a variety of chemicals. One technology system supplier indicated they were testing over 100 different solvents. Methods of contact between the gas and liquid solvents have been proposed that include conventional chemical tower packing and membranes. Fluid beds have been proposed for solid solvents. This analysis assumes that the next generation of advanced amine technologies will require 30 percent less steam and 10 percent less electrical power with an additional 15 percent improvement from FGR.

Once separated from the solvent, CO2 undergoes cleanup to remove any impurities including a dehydration step to remove any residual moisture, before entering the compressors. Compression of CO2 is accomplished by installing a multiple stage compressor located adjacent to the capture plant. The compressor is designed to compress the CO2 to approximately 2200 psig and will discharge directly into a sequestration pipeline. Because this equipment is large, it will be located on site to facilitate maintenance and repair operations.

Power will be supplied to the CO2 process equipment from a dedicated transformer. The transformer will be fed from the switchyard and located as close as practical to the high voltage source. An electrical and control room building will be provided for the CO2 capture facility. Control of the CO2 process will be from a dedicated PLC located inside the control room. Pertinent data will be fed back to the plant's main control room for remote monitoring capability and added safety. Plant communications will also be interconnected to the carbon capture plant along with major alarms.

Makeup water supplied to the new CO2 process equipment will be supplied from existing main plant system. The power plant water treatment facility will be designed to provide the additional makeup water, which will be for process use only. All cooling will be accomplished by direct air cooled heat exchangers. Depending on the process design, it may be necessary to

add mechanical chillers to provide the process temperatures required while working in the high California ambient temperatures.

## 4.2.2 NGCC with Capture Ready Design

Even if a carbon capture system is not included in the original plant design, certain provisions are recommended to minimize the cost of adding CCS in the future. Such provisions would include:

- HRSG exhaust breeching and stack connection to allow diversion of the exhaust gas to a CCS unit.
- Establishment of connections in the power cycle for steam extraction and condensate return.
- Provision of sufficient space adjacent to the HRSGs and the flue gas flow path for the CCS plant.
- Free and clear of encumbrances such as roads, underground facilities and overhead power lines.
- Provision of space in the switchyard for addition of an extra bay to supply the power needs of the CCS plant.
- Identify anticipated water source4 needs for the process and cooling in permit water balances. Include wastewater planning.
- Address sources of CO2 sales for utility credit as art of the Power Purchase Agreement. Identify none if this is not available.
- In addition to electrical trays mission and fuel source, the site selection and location should include CO2 transport and sequestration potential.
- Permit applications should address any expected hazardous materials and waste management.

#### 4.2.3 New Build Design

CB&I considered the impacts of incorporating the carbon capture system on the new build NGCC plant according to the following areas:

- Interface requirements
- Major plant design considerations
- Plant performance
  - o Capacity, heat input, and heat rate
  - o Water requirements
  - o Capacity factor

- o Availability
- Required equipment and space
- Modifications to water and wastewater
- Flue gas pretreatment
- Operations including operating flexibility and staff costs
- Carbon emissions

The descriptions and discussions are similar to the comparable retrofit evaluation included in Chapter 3.

#### 4.2.3.1 Interface Requirements

The following is a list of services provided by the power plant to the CO2 capture equipment:

- Flue gas from the HRSG exhaust
- Steam supply from the ST including condensate return
- Process water supply from the power plant water treatment facility
- Process water waste from the CO2 system to the power plant wastewater treatment and disposal system
- Power connection at the switchyard for a CCS transformer
- Plant communications systems
- Plant control systems
- Fire protection systems
- Maintenance and parts storage facilities
- Disposal of all waste material generated by CO2 capture process
- Potable water and sanitary systems including personnel facilities
- Parking for all employees

#### 4.2.3.2 Major Plant Design Considerations

The following list identifies major power plant design considerations required for inclusion of CO2 capture equipment:

- Connections at various locations within the power plant will be required to accommodate steam, water, controls and electrical power interfaces.
- Communications, electrical, piping and security equipment will need to be designed to include the CO2 capture equipment.

• The conventional NGCC plant arrangement will need to be modified to accommodate the CO2 capture equipment.

# 4.2.4 Plant Performance - Capacity, Heat Input and Heat Rate

Note that much of the information contained herein is similar to that previously discussed for the retrofit of the existing combined cycle power plant. The major difference is that the plant has been designed to accommodate a later design of the GE 7FA engines, 7FA.05. For the retrofit case the 7FA.04 engines were used since those are the machines that are utilized at Gateway.

Also note that all of the information discussed in this description refers to the heat balances for the NGCC. The heat balances were produced using Thermoflex (Tflex) software by the Thermoflow Corporation. Thermoflow has a current version of their software designated Thermoflow, Version 22. These heat balances were done on an earlier version, Version 20. The reason is that the combined cycle plant, which formed the basis for these balances were done on that version previously.

The combined cycle plant configuration for this study consists of the two GE 7FAs (7FA.05s) with HRSGs and one ST. The ST is of reheat design with a low pressure steam induction point. It is of single-flow design using HP steam; reheat steam at an intermediate pressure steam and LP steam. The plant uses only natural gas for fuel. There is a fuel gas heater which heats the CT fuel to 365°F using IP economizer discharge water. Gas used for duct burners is not heated (these are discussed below). CTs have inlet air chilling for use during the hottest times of the year. Chilling is not used in this study as the ambient temperature is relatively low, 61°F dry bulb (55°F wet bulb) based on temperatures in Stockton, Concord and Antioch, California which are the closest sources of weather data for the site near Vacaville, California.

A major aspect of this study is that all dry cooling is to be used. This includes an air-cooled condenser for the main power cycle, fin-fan coolers for the auxiliary cooling system water, fin-fan coolers for the CO2 capture system CO2 stripper outlet cooling water, and direct air cooling for the CO2 compressors.

Two heat balances were produced; one with the CO2 capture system ON and one with the CO2 capture system off.

It was assumed that the power generation heat input will remain constant with and without a carbon capture system. CB&I developed a cycle model using in-house data for the power plant and information from the advanced amine technology suppliers for the CCS system for a generic NGCC. The cycle model was developed specifically for California climatic conditions and utilization of dry cooling. Table 16 summarizes the key performance parameters for the generic NGCC with and without the advanced amine technology.

Table 16: Plant Performance for New Build With and Without Carbon Capture

	Without CCS	With Advanced Amine CCS
Net Capacity (MW) 1	607	540
Heat Input (MMBtu/hr) 1	4,174	4,174
Net Heat Rate (Btu/kWh) <sup>2</sup>	6,881	7,717

<sup>&</sup>lt;sup>1</sup>New & clean conditions

The CO2 capture system operation causes significant degradation in overall cycle performance. This is due to the extraction of IP-LP cross-over steam for the system reboiler and for the large auxiliary power requirements. The estimated performance breakdown is as follows in Table 17:

Table 17: Estimated Performance Breakdown for New Build with and without Carbon Capture

CO <sub>2</sub> Capture System Operating	No	Yes
Gross Plant Generation, MW	621	597
Total Auxiliary Power, MW	14	56
Net Plant Generation, MW	607	540
Net Plant Heat Rate, Btu/kWh HHV	6,881	7,717
	T	0.5
Gross Generation Reduction Due to Reboiler Steam Extraction, MW		25
Auxiliary Power Difference, MW		42
Total Net Power Reduction Due to CO <sub>2</sub> Capture System		67

Source: CB&I

#### 4.2.5 Water Requirements

The rates of water consumption and waste water production for CCS added to a New Build NGCC generating plant with dry cooling were estimated by developing a water balance based on a generic advanced amine system.

#### 4.2.6 Capacity Factor

Future capacity factors for the New Build Plant will depend upon a number of factors, including load growth, retirement decisions, generation expansion plans (including renewable additions), as well as future natural gas and CO2 allowance prices. CB&I conducted dispatch modeling of the WECC to project future capacity factors for the New Build Plant based on modeling assumptions agreed to with the Energy Commission. The dispatch modeling

<sup>&</sup>lt;sup>2</sup> Heat rate is based on a higher heating value (HHV)

included the projected CO2 allowance prices associated with the California cap and trade program in the dispatch price of all generating assets in WECC modeling domain<sup>14</sup>. The application of CO2 allowance prices in the dispatch price of non-California generating units was implemented as a means of addressing the requirement of AB 32 to prevent "leakage" (reduction of in-State emissions with parallel increase in emissions out of State). While this modeling approach may not exactly match the mechanisms California will ultimately utilize to address emissions from imported electricity, CB&I believes this approach to be reasonable and more representative of how AB 32 will affected generation in California than only applying the CO2 pricing to the California generating assets.

The first year of commercial operation of the New Build Plant with CCS was modeled in 2016. Although it is not likely that a new full-scale NGCC facility with CCS would be installed by this date, it is instructive to project its dispatch versus existing NGCC resources under the assumption of rapid CCS technology adoption by the New Build Plant. The New Build Plant with CCS was modeled in the California independent System Operator (CAISO) North transmission area, which includes Vacaville, California.

The New Build Plant with CCS is projected to dispatch at an average capacity factor of 77% for the period 2016 to 2034 (87 percent for the period 2016 through 2025). The capacity factor for the New Build Plant with CCS is projected to decline in later years as new NGCC units (without CCS) come online. The decline in capacity factor in the later years would likely be reduced if the new NGCC units were also required to install CCS. Although the New Build Plant with CCS has a higher heat rate than many existing NGCC units, the combination of reduced CO2 emissions, and projected increasing CO2 prices through 2020 allow the unit to run just behind existing NGCC units without CCS. As the projected CO2 prices level off after 2020 and gas prices continue to increase over time, the New Build Plant with CCS begins to lose its relative dispatch price advantage to existing NGCC without CCS.

With CCS installed on the New Build Plant, the dispatch cost for this facility would change relative to the dispatch cost of New Build Plants without CCS. Fuel cost on a \$/MWh basis would increase due to the higher net plant heat rate associated with the CCS retrofit. Variable O&M costs on a \$/MWh basis would increase due to heat rate impacts and the incremental variable costs associated with the carbon capture system<sup>15</sup>. The CO2 price component of the dispatch cost would be less at New Build Plants with CCS due to the lower emissions of CO2 per MWh of generation. This assumes the California cap-and-trade program ultimately recognizes CCS as a viable control mechanism for reducing GHG emissions to the atmosphere and does not require allowances for properly sequestered CO2. Depending upon natural gas and CO2 allowance prices, and incremental variable O&M costs for the CCS system, it is possible the net impact of CCS addition to the dispatch cost of the New Build Plant could be

<sup>&</sup>lt;sup>14</sup> Initial modeling that applied CO2 allowance prices in the dispatch cost to only California generating plants resulted in large increases of imported power from other WECC facilities.

<sup>&</sup>lt;sup>15</sup> The operating and maintenance costs of the CO2 pipeline and the CO2 sequestration operations have been included as fixed O&M category and therefore do not affect the dispatch price.

either negative or positive. It should be noted that small changes in assumptions concerning natural gas and CO2 allowance prices can alter the relative dispatch position of New Build Plants with CCS relative to New Build Plant without CCS installed.

Based on the preliminary dispatch modeling for the New Build Plant with CCS, it is recommended that a base case capacity factor of 80 percent be used in the life cycle cost model simulations of this facility. Due to the many variables that can impact future capacity factors and the uncertainties associated with long term projections of these key variables, it is suggested that the life cycle cost model evaluate a range of capacity factors from 50 percent to 90 percent. Additionally, as a policy measure to encourage CCS, a must-run designation could be assigned to some of the first units with CCS, for at least some of the remaining life. Such a policy is expected to require funding to support operation of facilities at capacity factors that exceed their economic dispatch.

#### 4.2.7 Availability

The same 93 percent availability used in the Retrofit evaluation was used in the New Build evaluation as the basis was identical.

## 4.2.8 Required Equipment and Space

The CO2 capture equipment will be located close to the HRSGs to minimize duct length. A conceptual site plan arrangement showing the locations and physical sizes of the new carbon capture equipment and ancillaries relative to a typical NGCC site is shown in the following Figure 12.

COL CONTACT

COLOREDO

COL NEW COS CAPTURE EMPINENT BOUNDARY 3.7 ACIES APPROX. 002 NE DE TO 100,678410N

Figure 12: Conceptual Site Plan Arrangement



#### 4.2.9 Modification to Water and Waste Water

The description of modification to water and waste water is similar as that for the retrofit evaluation.

#### 4.2.10 Flue Gas Pre-Treatment

The description of flue gas pre-treatment is similar as that for the retrofit evaluation.

#### 4.2.11 Impact on Operations

The primary factors affecting power plant operating flexibility are:

- Startup time HRSG drum heat up rate and ST heat up rate.
- Load ramp rate ST temperature differentials.
- Turndown CT minimum load.

The carbon capture system will not affect any of the factors listed above. For discussion on the basis for this conclusion, refer to Reference A10.

#### 4.2.12 Operations & Maintenance Staffing

The description of staffing is similar as that for the retrofit evaluation.

#### 4.2.13 Carbon Emissions

The CO2 emissions were calculated for the New Build plant with and without a carbon capture system. The CO2 emissions are based on a carbon capture system that is designed for 90 percent CO2 removal typical gas-fired flue gas composition; and flue gas quantities calculated by the Thermoflex heat balance model. Table 18 summarizes the carbon emissions, with and without carbon capture.

Table 18: CO2 Emissions for New Build With and Without Carbon Capture

	Without CCS	With Advanced Amine CCS
CO <sub>2</sub> Emissions (lb/hr)	485,750	48,575

Source: CB&I

# 4.3 Cost Analysis

A cost analysis was performed to compare the cost for a New Build plant with and without a carbon capture system; the selected carbon capture technology is a next generation advanced amine technology. The analysis compares the capital costs, levelized costs of electricity produced and the cost of CO2 avoided. The levelized cost analysis accounts for capital carrying charges, replacement power and capacity factors for a typical California New Build NGCC plant with and without a carbon capture system. The Model that was described in the section, "Development of the Engineering Options Analysis Procedure" was used and the cost components of the Model consist of the following:

Capital costs for a New Build plant with and without a carbon capture system.

- Capital costs for a CO2 transportation pipeline and injection system. In the New Build scenario wellhead pumps are considered but a booster pump along the route is not assumed necessary.
- Incremental fixed and variable O&M cost for the carbon capture system.
- Incremental fixed and variable O&M cost for the CO2 transportation pipeline and injection system.
- CO2 emissions penalty

# 4.3.1 Capital Cost Summary

The EPC costs for carbon capture can be broken down into four general categories shown in Table 19:

Table 19: EPC Cost for New Build Carbon Capture (\$ million) – 2012

	Cost	Percentage
Carbon Capture System	\$548	65.8%
Compression	\$78	9.4%
Cooling	\$76	9.1%
Balance of Plant	\$131	15.8%
Total Carbon Capture EPC Cost	\$833	100%

Source: CB&I

The bulk of the cost is from the carbon capture system. Compression includes compressors, dryers, and fans. Cooling includes cooling system area and chiller piping. These costs include direct materials cost, direct labor cost, and indirects (distributables, home office services, start-up support, transportation, etc.).

Table 20 summarizes the capital costs a New Build NGCC plant both with and without a CO2 capture system. Overnight capital cost includes the EPC cost, owner's cost, and project contingency, but excludes interest during construction interest and inflation and escalation. Overnight capital cost expressed in \$/kW is a commonly used metric to compare the capital costs of different projects.

Table 20: Capital Costs for New Build NGCC Plant With and Without Carbon Capture (\$ million) – 2012

	Base Plant without CCS	Plant with Advanced Amine CCS
Power Plant	\$664	\$678
Carbon Capture EPC Cost	-	\$833
CO <sub>2</sub> Injection System EPC Cost	-	\$23
CO <sub>2</sub> Transportation EPC Cost	-	\$29
Total EPC Cost	\$664	\$1,563
Owner's Cost	\$30	\$45
Interest During Construction	\$73	\$170
Inflation and Escalation	\$32	\$74
Project Contingency	\$66	\$156
<b>Total Capital Cost</b>	\$865	\$2,008
Overnight Capital Cost	\$1,252/kW	\$3,267/kW

The capital cost estimate for CCS on a New Build NGCC took into account the following key components:

- NGCC Power Plant
- Carbon Capture System
  - o Cooling System
  - o Compressors
  - o Power Supply System
  - o CCS Power Supply from the Power Plant
  - o Arrangement of Switchyard Components to Accommodate the New CCS Equipment
  - o Power Supply Cost Basis
- CO2 Transportation Pipeline
  - o Pipeline Routing

- o Back Pressure Caused by Failure of Compression
- o Isolation of Pipeline Segments in the Case of a Leak
- o Depressurization of Discreet Pipeline Segments
- o Emergency Shutdown Valve
- Basis of Cost
- o Power Supply
- o Shipping
- o Labor and Equipment
- o Civil Work
- o Pre Installation Labor Costs
- CO2 Injection System
  - o Pre-operation Geological Assessment and Preparation of the Geologic Model
  - o Investigation Drilling and Testing of the Target Horizon by the First CO2 Injection Well
  - o Installation of Two Additional CO2 Injection Wells
  - o Installation of Six CO2 Monitoring Wells
  - o Monitoring during the Operation of CO2 Injection System
  - o CO2 Monitoring During the Post Closure Period

#### 4.3.2 Operation & Maintenance Costs

The O&M costs consist of fixed and variable O&M cost components. The O&M costs include the costs needed to operate and maintain a state of the art New Build plant, both with and without a CO2 capture system. The O&M costs do not include fuel costs, replacement power costs, or carbon penalty costs (also referred to as carbon emissions allowance cost). The O&M costs do, however, include ongoing capital improvements or replacements associated with the installed systems that were not included in the upfront capital costs. The O&M costs are based on information from typical NGCC plants and are not specific to California since actual values from California plants were not available.

#### 4.3.2.1 Fixed Operation and Maintenance

The discussion of the fixed O&M cost is the same as for the retrofit evaluation above, in section "Application of the Retrofit Engineering Options Analysis Procedure"; the only difference is that major maintenance and capital improvement cost is based on 25 percent of CCS system cost per previous CB&I studies, adjusted for the maturity of the CCS technology.

#### 4.3.2.2 Variable Operation & Maintenance

The variable O&M includes the O&M costs that vary depending on how much the plant is operated and the amount of carbon that is captured. The variable O&M of the carbon capture system is expressed as a cost per year divided by the annual amount of electricity production. The variable O&M for the carbon capture system includes the cost of solvents/reagents, makeup water, solvent/reagent disposal, and waste water disposal. Note that variable O&M does not include the power required to operate the compressors that are part of the plant carbon capture system as these loads are internal to the plant and are accounted for in the replacement power category. The base rates are identical to those used in the retrofit evaluation, above.

#### 4.3.2.3 Total Operations and Maintenance Cost Summary

Included in the fixed and variable O&M cost inputs is the cost to monitor the CO2 extraction, transportation and storage systems during the operation of plant. The O&M inputs for a state of-the-art New Build NGCC, both with and without a CO2 capture system are summarized in Table 21.

Table 21: Estimated O&M Costs for New Build NGCC Plant With and Without Carbon Capture (2012\$)

Fixed O&M (\$ per kW yr) <sup>1, 2</sup>	Base Plant without CCS <sup>1</sup>	Base Plant with Advanced Amine CCS <sup>2</sup>
Power Plant	9.5	10.7
Fixed O&M Cost with CCS	-	5.4
CO <sub>2</sub> Transportation and Injection Fixed O&M Cost	-	3.0
Total Fixed O&M Cost	9.8	19.1
Variable O^M (\$ per MWh) 1, 2		
Power Plant	3.2	3.6
Variable O&M Cost for CCS	-	3.1
CO <sub>2</sub> Transportation and Injection Variable O&M Cost	-	-
Total Variable O&M Cost	3.2	6.7
<sup>1</sup> Based on nominal 607 MW average net rating for <sup>2</sup> Based on nominal 540 MW average net rating for		

#### 4.3.3 Revenue

Typically levelized cost comparisons only consider direct electrical energy costs because electricity is the product and the only source of revenue. For a levelized cost comparison involving plants that have other sources of revenue besides electricity, credits or reductions are given for the other sources of revenue. This Model is set up to account for a reduction in ancillary services revenue due to a lower capacity and less generation or an additional revenue source of CO2 sales for EGR or EOR.

#### 4.3.4 Economic and Price Inputs

The economic inputs used for the new build evaluation are the same as for the retrofit evaluation; see the section "Application of the Retrofit Engineering Options Analysis Procedure" for the details.

#### 4.4 New Build NGCC Base Case Results

The two key figures of merit included in the results are the incremental levelized COP in \$/MWh and the cost per avoided CO2 emissions in \$/ton CO2. The incremental levelized COP accounts for the additional costs and revenues that are associated with a CCS retrofit. Both capital and O&M costs are included. The effect of reduced performance, including capacity derates, increased internal loads, and capacity factor reductions is reflected in the smaller electricity production and associated increases in each component of the levelized costs of production. The cost per avoided CO2 emissions accounts for the levelized cost and also the amount of CO2 emissions that are avoided by installing the retrofit. The avoided CO2 emissions account for the CO2 captured in the CCS system.

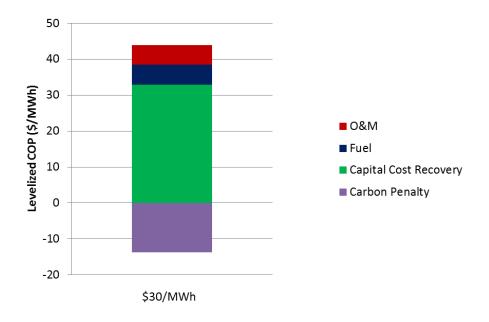
The total levelized costs of production for the NGCC plant with and without CCS are shown in Figure 13 below.

140
120
120
80
60
Capital Cost Recovery
Carbon Penalty
Ancillary Services Revenue

Figure 13: Levelized COP for New Build NGCC Plant With and Without Carbon Capture

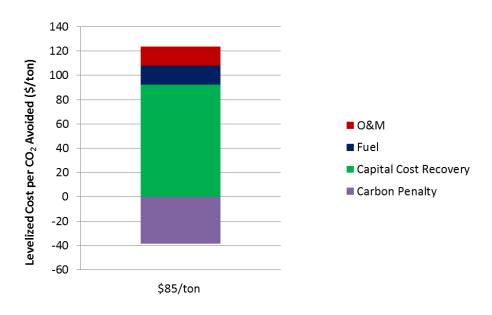
The incremental levelized COP is \$30/MWh and the cost per avoided CO2 emissions is \$85/ton CO2. Figure 14 and Figure 15 below show the breakdown of the incremental levelized COP and cost per avoided CO2 emissions.

Figure 14: Incremental Levelized COP for New Build NGCC Plant with Carbon Capture



Source: CB&I

Figure 15: Incremental Levelized Cost of Avoided CO<sub>2</sub> Emissions for New Build NGCC Plant With Carbon Capture



Capital costs are the most substantial component of the levelized cost economics. Avoided carbon penalty costs, O&M, and fuel are less significant contributors and ancillary services revenue has virtually no effect. CO2 sales are not included in the base case but one can see the moderate effect on the overall economics in the sensitivities in the next section. The relatively high values for these metrics in comparison to other studies are due primarily to the large effect that dry cooling has on cost and performance.

#### 4.4.1 Sensitivity Analysis for New-Build NGCC with CCS Case

#### 4.4.1.1 Overview

Due to uncertainties necessarily inherent in relying on assumptions and projections, it should be anticipated that actual results would differ based on the assumptions used. In order to demonstrate the impact of certain circumstances on the study results, CB&I developed sensitivity analyses to key assumptions. It should be noted that other examples could have been considered, and those presented are not intended to reflect the full extent of possible impacts on the study.

As part of the technical evaluation of the new build options, CB&I determined that there are many design sensitivity analyses which could be performed such as: exhaust gas recirculation, number of water-gas shift stages, alternative steam/CO2 turbine configurations, ASU oxygen purity, solvent loop in HRSG, and capture-ready new plant without CCS. Rather than conducting sensitivity analyses to determine the optimal design, CB&I considered all these factors and developed the best case design based on the technology that is available today. The sensitivity analyses instead focused on key input parameters that impact the lifecycle economics: capacity factor, CCS equipment cost, CCS capacity impact, CO2 emissions penalty price, CO2 sales revenue, discount rate, and fuel price.

#### 4.4.1.2 Sensitivity Cases

CB&I has incorporated in the Model several sensitivity analyses by varying the specific key input parameters listed in Table 22 (see the section on sensitivity cases for the retrofit evaluation, above, for more complete descriptions of each sensitivity parameter):

Table 22: Sensitivity Parameters and Ranges for New Build NGCC Plant

Sensitivity Parameter	Sensitivity Range		
Capacity factor (%)	50% - 90%		
CO <sub>2</sub> Emissions Penalty (\$/ton CO <sub>2</sub> )	\$18.40 ±\$7.50		
CO <sub>2</sub> Sales Revenue (\$/ton CO <sub>2</sub> )	\$0, \$10 ±\$5 (CO <sub>2</sub> transportation and injection costs are included only in the base case which assumes no CO <sub>2</sub> sales)		
CCS Equipment Capital Cost (% of base)	-30% +50% of base CCS equipment cost		
CCS System Capacity Impact (MW reduction)	±10 MW		
Discount Rate (%)	3% - 6%		
Natural Gas (\$/MMBtu)	\$4.56 ±25%		

# **Sensitivity Results**

The sensitivity results are shown in Table 23 below:

Table 23: Sensitivity Results for New Build NGCC Plant with Carbon Capture

		Capacity Factor	CO₂ Penalty	CO₂ Sales Price	CCS Equipment Capital Cost	CCS Performance Impact	Discount Rate	Natural Gas Price
	Base Case	80%	\$18.40/ton	No sales	Base Cost	Base Performance	5%	\$4.56/MMBtu
Parameter	Upper Sensitivity	90%	\$25.90/ton	\$15/ton	+50%	+10 MW	6%	\$5.70/MMBtu
	Lower Sensitivity	50%	\$10.90/ton	\$5/ton	-30%	-10 MW	3%	\$3.42/MMBtu
	D C				\$30/MW	h		
	Base Case				\$85/ton			
	Upper	\$26/MWh	\$25/MWh	\$23/MWh	\$44/MWh	\$32/MWh	\$35/MWh	\$32/MWh
Results	Sensitivity	\$75/ton	\$70/ton	\$64/ton	\$124/ton	\$91/ton	\$99/ton	\$89/ton
	Lower	\$51/MWh	\$36/MWh	\$28/MWh	\$22/MWh	\$28/MWh	\$21/MWh	\$29/MWh
Source: CD91	Sensitivity	\$143/ton	\$101/ton	\$78/ton	\$62/ton	\$80/ton	\$60/ton	\$81/ton

The three parameters that have the largest sensitivity ranges are capacity factor, CCS equipment cost, and discount rate. The results are shown in Figure 16, Figure 17, Figure 18 and Figure 19 below. The most economic cases will be dispatched as much as possible and thus have a higher capacity factor, will have the lowest CCS equipment costs and thus the lowest capital costs, and will have the most favorable financing and thus the lowest discount rate.

Figure 16: Sensitivity of Levelized COP to Capacity Factor, CCS Cost and Discount Rate (New Build)

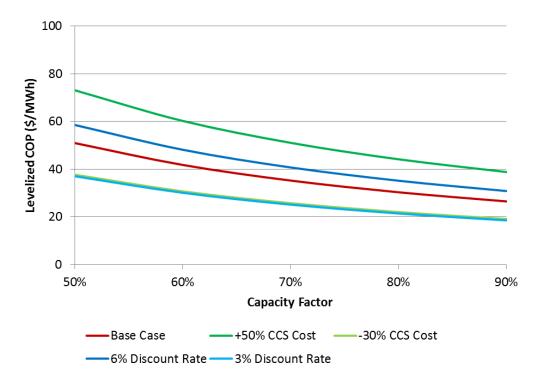
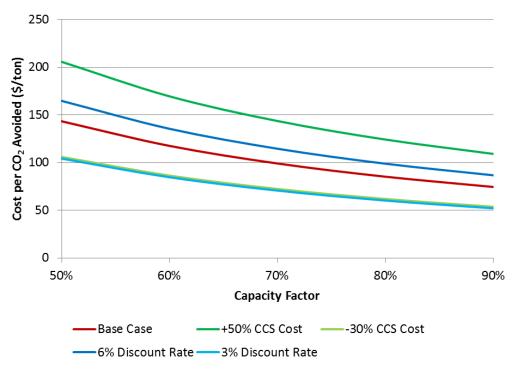
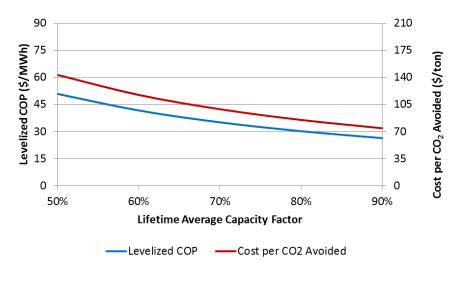


Figure 17: Sensitivity of Levelized Cost of Avoided CO2 Emissions to Capacity Factor, CCS Cost and Discount Rate (New Build)



In addition to the sensitivity analysis summarized in the above table, parametric studies were also conducted for capacity factor and CO2 sales for EOR. The results are shown in the figures below.

Figure 18: Sensitivity of Costs to Capacity Factor for New Build NGCC Plant with Carbon Capture



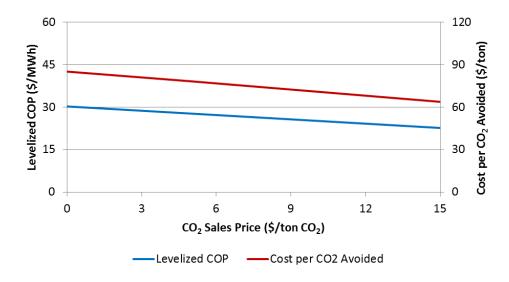


Figure 19: Sensitivity of Costs to CO2 Sales Price for EOR (New Build NGCC with Carbon Capture)

# 4.5 Findings and Conclusions

Several findings and conclusions resulted from the retrofit and new build evaluations:

- Consider design options to the CCS that would address some of the concerns of implementing a CCS to NGCC plants in California.
- Design options would include FGR and other cooling options for the CCS that would allow the use of wet and dry cooling.
- Propose a pilot plant that would be capable of demonstrating CCS performance characteristics while operating in California under the regulations to limit water consumption.
- The economic sensitivities for both the retrofit and new build evaluations show that the Levelized COP is sensitive primarily to the plant capacity factor, indicating that one or more means to improve plant dispatch are needed to effectively reduce the Levelized COP.

CB&I found that, based on the economic evaluations for both for the Retrofit and New Build cases, the Levelized COP for NGCC plants with carbon capture is significantly high as a result of California climate conditions, constraints on water consumption and the operating regime of NGCC plants in California. Improvements to the economics must be found, tailored to California's specific needs. As a result, the recommendation for further work focused on FGR and other cooling options such as wet/dry cooling, and on paths to developing a Pilot Plant, all of which are described in Chapter 5.

# **CHAPTER 5:**

# Summary of Preliminary Scope, Cost Estimate, and Schedule for a California Pilot-Scale Technology Validation Test of an Ngcc Plant With a Ccs Application

The original scope of work for the Study included identifying a specific CO2 extraction technology and identifying a host site for a pilot plant. In lieu of this design basis information, the Study considered design considerations to the CCS that would address some of the concerns of implementing a CCS to NGCC plants in California. Particular areas of interest are California regulations that limit water consumption, ways to lower capital costs and options to the combustion cycle. Two options were considered for further evaluation as part of the pilot plant feasibility study. These would involve modifications to the new build case as follows:

- Incorporation of FGR
- Utilization of treated waste water for cooling the carbon capture process

A major goal of the pilot plant feasibility study is to identify technologies and CCS configurations that are viable for testing. In addition, CB&I developed a pilot plant project charter that highlights the project development plan, the project documents, and commercial arrangement to move the pilot plant project forward.

# 5.1 Additional Options Evaluated

The three additional options that were evaluated in addition to the new build base case and the base case with CCS are:

- New build NGCC plant with CCS and 40 percent FGR (with dry cooling as in the base case).
- New build NGCC plant with CCS and 40 percent FGR and hybrid cooling.
- New build NGCC plant with CCS and 40 percent FGR and wet cooling.

The cost and performance for each of these options is evaluated by using the base case with full flow CCS dry cooling as the basis and adapting or adding systems as necessary.

#### 5.1.1 CCS with 40 Percent FGR

FGR technology recirculates a portion of the flue gas exiting the HRSG back to the CT inlet, reducing the volume of gas being processed by the flue gas cooler, booster fan, and absorber in the carbon capture system. Although there have been no large scale demonstrations, studies by major CT suppliers indicate that up to 40 percent of the flue gas can be recirculated without adversely affecting CT operation. The reduction in flow through the cooler, booster fan, and absorber is expected to reduce the size and cost of this equipment. In addition, the increased concentration of CO2 in the flue gas is expected to improve the efficiency of the absorber.

Preliminary information from the CT suppliers indicates that the recirculated flue gas must be cooled sufficiently to minimize the impact on the CT, which is accomplished through a recirculation loop that uses waste water from the carbon capture cycle and introduces it to the CT inlet air stream before the inlet air chiller. To minimize fresh water consumption, an efficient direct contact cooler (along with a moisture separator and booster fan) was selected, which utilizes treated reject water from the carbon capture cycle with supplementation from fresh water. Although this approach provides the simplest flue gas recycle system, it does not necessarily provide the best overall plant performance. Trial optimization studies of different recirculation system cooling designs indicate that utilization of a more elaborate cooling system for the recirculated flue gas may improve the plant output by as much as 10 percent with a slight improvement in efficiency.

# 5.1.2 CCS with 40 Percent FGR and Hybrid Cooling

In addition to 40 percent FGR, this case utilizes a common practice in the power industry of using treated effluent from municipal wastewater treatment facilities. Because waste water availability will vary with the plant site, this intermediate case assumes 50 percent of the heat load handled by a dry cooling system similar to the new build study and 50 percent handled by a conventional wet cooling tower, in the form of a wet-dry cooling tower where indirect heat exchange surface (dry) is added above the direct contact (wet) section.

#### 5.1.3 CCS with 40 Percent FGR and Wet Cooling

In this case, 100 percent of the carbon capture system cooling duty is handled by a wet cooling tower. Due to the efficiency of direct, evaporative cooling, this case, utilizing a conventional, wet, forced draft cooling tower, offers the highest efficiency at the lowest cost.

#### 5.2 Performance

The CT manufacturers did not provide sufficient data on the effect of FGR on CT performance to provide a detailed analysis. Thus, CB&I developed the heat balances using industry standard performance data. CB&I utilized the Thermoflex power cycle program to build a hypothetical FGR loop and incorporate it into the heat balances developed for the new build option, with and without CCS, which was described earlier in Chapter 2. From this basis, the performance impacts and equipment sizes were developed to support the economic analysis presented in Chapter 2.

FGR and wet cooing affect both output and efficiency as shown in the table below. It should be noted that the heat balances developed in Chapter 2 incorporate a CT inlet air chiller to provide higher plant output at high ambient temperatures. To enable comparison with other current FGR studies, the heat balances reported in Table 24 below were run at comparable ambient conditions without the inlet chiller and are thus not directly comparable with those described in Chapter 2.

**Table 24: New Build Performance Summary1** 

	Without CCS	With Advanced Amine CCS	With CCS and 40 Percent FGR	With CCS, 40 Percent FGR, and Hybrid Cooling	With CCS, 40 Percent FGR, and Wet Cooling
Net Capacity (MW)	607	540	498	500	502
Auxiliary Power (MW)	14	56	48	45	44
Gross Capacity (MW)	621	597	546	546	546
Heat Input (MMBtu/hr HHV)	4,174	4,174	3,823	3,823	3,823
Net Heat Rate (Btu/kWh) <sup>2</sup>	6,881	7,717	7,682	7,643	7,616
Net Heat Rate (Btu/kWh) <sup>3</sup>	6,208	6,963	6,931	6,910	6,885

<sup>&</sup>lt;sup>1</sup>New & clean conditions

The primary factors affecting power plant operations from implementing FGR and wet cooling are:

- Startup The startup of the CT will be affected by the time and processes needed to
  introduce the recirculated flue gas stream into the air inlet (once the plant is at full load
  and the CCS is ready for service). Startup time for the CCS with wet cooling should be
  shorter than for dry cooing since the greater efficiency of wet cooling will allow CCS
  operating temperatures to be established faster.
- Load ramp rate Experience with power augmentation methods that involve increasing mass flow, similar to FGR, indicates that the ramp rates will need to be slightly slower. Wet cooling towers typically have a faster response than dry coolers so the ability of the CCS to follow power plant ramping may improve slightly.
- Turndown Experience with similar systems indicates that turndown will be more
  complicated, with the possibility that different minimum loads will result with and
  without FGR. While wet cooling is not expected to affect power plant minimum load,
  the ability of the CCS to operate at lower loads may be enhanced by the increased
  flexibility offered by wet cooling.

<sup>&</sup>lt;sup>2</sup> Heat rate is based on a higher heating value (HHV)

<sup>&</sup>lt;sup>3</sup>Heat rate is based on a lower heating value (LHV)

#### 5.3 Environmental

Environmental concerns can only be discussed in a general way until the host pilot plant facility is identified and a site-specific evaluation of the selected technology is completed.

Implementation of FGR will reduce the wastewater discharges due to the re-use of CCS blowdown water for cooling the FGR loop. Implementation of wet cooling will increase the waste water discharges due to the need for blowdown from the evaporative portion of the cooling system.

Air emissions may be affected by the implementation of FGR; however, until detailed data is available from the CT manufacturers, the effects on the CT emissions cannot be estimated. Air emissions from the wet cooling system cooling towers will need to be considered and will be similar to those from conventional NGCC power plants with wet cooling towers.

No new consumable materials are expected to be required for the FGR option. The wet cooling options will require additional materials for the makeup waste water treatment systems and for chemistry control of the wet cooling loops and will be similar to those used in conventional NGCC power plants with waste water makeup and wet cooling towers.

Implementation of FGR can be expected to result in additional solid wastes from the purification system for the direct contact cooling water. While the re-use of CCS waste water for flue gas cooling will reduce the overall waste water quantity, the reject water from the water purification system will be more highly concentrated and can be expected to require additional treatment. Depending on the quality of waste water used for cooling system makeup, the water treatment system may produce considerable quantities of solid waste (but it is usually considered to be non-hazardous and can be disposed of in a conventional landfill).

#### 5.4 Economics

Evaluating the lifecycle economics is an important part of a feasibility study for a pilot plant because the funding of a pilot plant project is contingent on having a path to favorable economics for follow-on commercial plants. A lifecycle cost model was to evaluate the retrofit and new build NGCC plants as well as the additional design options in order to better evaluate the economics of a pilot plant in California.

Table 25 summarizes the capital costs for a New Build NGCC plant both with and without a CO2 capture system and with the three other design options.

Table 25: New Build Capital Cost Summary (\$ Million) - 2012\$

	Without CCS	With Advanced Amine CCS	With CCS and 40Percent FGR	With CCS, 40 Percent FGR, and Hybrid	With CCS, 40 Percent FGR, and Wet Cooling
Power Plant	\$664	\$678	\$678	\$678	\$678
Carbon Capture EPC Cost	-	\$833	\$768	\$704	\$695
CO <sub>2</sub> Injection System EPC Cost	-	\$23	\$23	\$23	\$23
CO <sub>2</sub> Transportation EPC Cost	-	\$29	\$29	\$29	\$29
Total EPC Cost	\$664	\$1,563	\$1,499	\$1,434	\$1,426
Owner's Cost	\$30	\$45	\$45	\$45	\$45
Interest During Construction	\$73	\$170	\$163	\$156	\$155
Inflation and Escalation	\$32	\$74	\$71	\$68	\$67
Project Contingency	\$66	\$156	\$150	\$143	\$143
Total Capital Cost	\$865	\$2,008	\$1,927	\$1,846	\$1,835

Table 26 summarizes the O&M costs a New Build NGCC plant both with and without a CO2 capture system and with the three other design options.

Table 26: New Build O&M Cost Summary (2012\$)

	Without CCS	With Advanced Amine CCS	With CCS and 40Percent FGR	With CCS, 40 Percent FGR, and Hybrid Cooling	With CCS, 40 Percent FGR, and Wet Cooling
Net Capacity Basis (MW)	607	540	498	500	502
Fixed O&M (\$/kW-yr)					
Power Plant	9.5	10.7	11.6	11.6	11.5
Carbon Capture Fixed O&M Cost	-	5.4	5.8	5.8	5.8
CO <sub>2</sub> Transportation and Injection Fixed O&M Cost	-	3.0	3.2	3.2	3.2
Total Fixed O&M Cost	9.5	19.1	20.6	20.6	20.5
Variable O&M (\$/MWh)					
Power Plant	3.2	3.6	3.9	3.9	3.9
Carbon Capture Variable O&M Cost	-	3.1	3.4	3.5	3.6
CO <sub>2</sub> Transportation and Injection Variable O&M Cost	-	-	-	-	-
Total Variable O&M Cost	3.2	6.7	7.3	7.4	7.4

Source: CB&I

The capital costs estimated by CB&I were compared to a *Cost and Performance Baseline for Fossil Energy Plants: Volume 1: Bituminous Coal and Natural Gas to Electricity*" DOE/NETL-2010/1397, Revision 2. CB&I's cost estimate is higher for several reasons, including:

- Significant balance of plant scope and costs (both material and labor) associated with the CCS system appear to be either omitted or underestimated in the DOE/NETL report.
- Utilizing more expensive dry cooling instead of wet cooling for the power plant and CCS system.
- Higher labor cost in California compared to the Midwest.

• EPC contracting structure assumed instead of EPCM contracting structure (which monetizes more of the risk in the cost estimate).

The labor cost and cooling system are California specific items that cause the CB&I cost estimate to be higher. The other items are the result of different cost estimate scopes and different contracting structures. CB&I's cost estimate includes the scope necessary to construct the integrated power plant and CCS system and includes the monetized risk that will be associated with an EPC contracting structure.

The cost and performance results summarized above are used as inputs to the lifecycle economic model, along with economic and price assumptions, revenue assumptions, and additional performance inputs such as availability, capacity factor, and CO2 emissions. The resulting lifecycle levelized costs of production for the base case and all the CCS cases are shown in Figure 20 below.

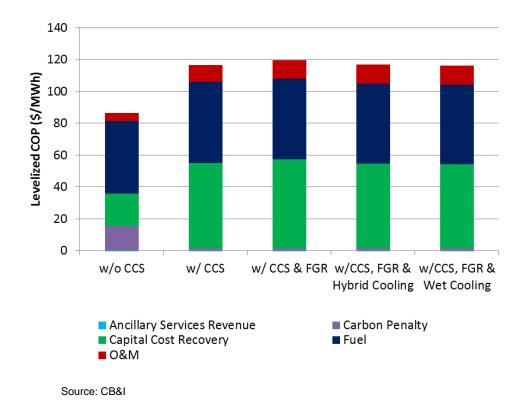


Figure 20: New Build Levelized COP

Capital costs are the most substantial component of the levelized COP economics. Avoided carbon penalty costs, O&M, CO2 sales, and fuel are less significant contributors, while ancillary

services revenue has virtually no effect.

The two key figures of merit included in the results are the incremental levelized COP in \$/MWh and the levelized cost per avoided CO2 emissions in \$/ton CO2. The results for each case are shown in Figure 21 and Figure 22 below.

\$33/MWh \$30/MWh \$30/MWh \$30/MWh 50 40 Levelized COP (\$/MWh) 30 20 10 0 -10 -20 w/ CCS w/ CCS & FGR w/CCS, FGR & w/CCS, FGR & Hybrid Cooling Wet Cooling ■ Ancillary Services Revenue ■ Carbon Penalty ■ Capital Cost Recovery ■ Fuel ■ 0&M

Figure 21: New Build Incremental Levelized COP

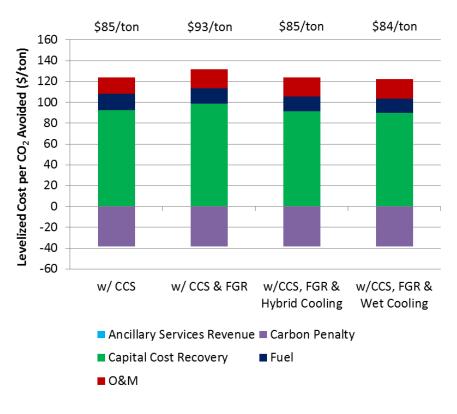


Figure 22: New Build Incremental Levelized per Avoided CO2 Emissions

CCS with FGR has virtually the same levelized COP as the Base Case with CCS. The decrease in CCS system cost is almost exactly offset by the decrease in net power output and the increase in O&M cost. The hybrid and wet cooling cases show reductions in the levelized costs of production compared to the other CCS cases that use dry cooling for the CCS system. The reductions in cost due to the less expensive cooling system and more efficient CCS system offset the loss in net power output from FGR and the slightly increased O&M costs. Wet cooling is less expensive than hybrid cooling on a levelized COP basis, but the difference is quite minimal. Note that trial optimization studies of the FGR design indicate that further modifications to the FGR gas cooling system may increase the plant output by as much as 10 percent without adversely affecting efficiency. Such modifications would increase the capital cost of the FGR system; however, the associated increase in plant output has the potential to reduce the incremental levelized COP for all three of the FGR cases below that of the base case with CCS but without FGR.

The three parameters that have the largest sensitivity ranges are capacity factor, CCS equipment cost, and discount rate. The most economic cases will be dispatched as much as possible and thus have a higher capacity factor, will have the lowest CCS equipment costs and thus the lowest capital costs, and will have the most favorable financing and thus the lowest discount rate. With a 90 percent capacity factor and either a CCS cost at 30% less than the base cost or a

discount rate of 3 percent, the incremental levelized COP for the CCS with FGR and wet cooling case is slightly less than \$20/MWh and the levelized cost per CO2 avoided is slightly more than \$50/ton. In a very favorable technical, financial, and power market environment, if a project that utilized CCS with FGR and wet cooling was able to achieve a capacity factor of 90 percent, a CCS cost at 30 percent less than the base cost, and a discount rate of 3 percent, the incremental levelized COP for the CCS with FGR and wet cooling case could be as low as \$13/MWh and the levelized cost per CO2 avoided could be as low as \$37/ton. Optimization of the FGR system has the potential to reduce the costs even further.

# **CHAPTER 6:**

# Preliminary Scope, Cost, and Schedule for a Pilot-Scale Technology Validation of Ngcc With Ccs In California

# 6.1 Project Charter

The pilot plant project charter (Project Charter) should be developed to identify the final pilot plant size, performance requirements, and site conditions for specifically implementing the requirements of the main contracts, sub contracts, Energy Commission specific requirements culminating in a commercial arrangement with the intent that the most cost competitive solution can be obtained, a reasonable performance can be expected and valuable testing proves commercial viability for the state of California.

In order for a power project to be financed and built, a project development plan should be developed. A major part of the project development plan is to identify and begin to generate the major project documents, which are required to support financing. Project documents must meet the following three general requirements:

- Complete and clear technical definition of the project
- Commercial arrangements through contracts and agreements addressing key responsibilities
- Implementation planning based on adequate skills, experience, budgets, and schedules

An example of a commercial arrangement for a power project, focusing on the major agreements that are a major part of the project documents, is shown in Figure 23 below.

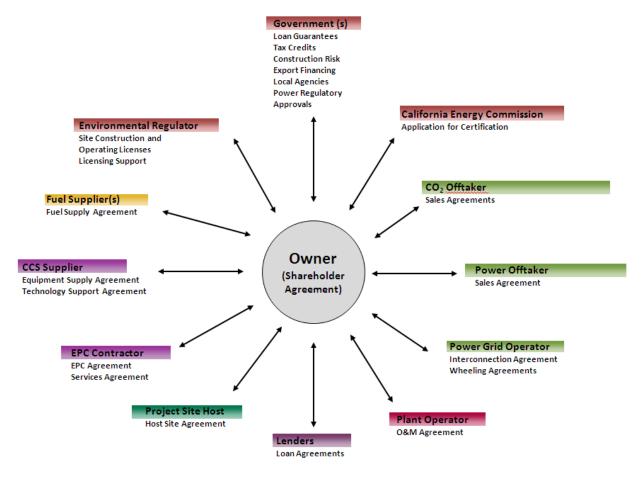


Figure 23: Example of a Commercial Arrangement for a Power Plant

Source: CB&I

Critical issues early in the project development process for a NGCC plant with CCS in California include: development phase implementation plans, major financial agreements, and project definition. These documents, although they need to be drafted early on, will continue to evolve and will be updated to reflect more details and changes that occur as the project progresses. Implementation planning documents for the planning phase must be developed early on, including:

- Environmental permitting plan
- Public outreach plan
- Financing plan
- Contracting strategy
- Project schedule
- Project cost estimate

#### Financial model

Major project agreements that must be developed early on include: the ownership agreement, the host site agreement, and support agreements at the federal, state, and local levels. Support agreements could include legislative or regulatory support for issues such as must-run designation to guarantee a sufficiently high level of dispatch into the power market, legislation or regulations to encourage utilities to enter into Power Purchase Agreements, CO2 storage liability limitations. Direct funding support, loan guarantees, tax credits, preferential tax treatment (e.g., accelerated depreciation or income or property tax exemptions), and eminent domain rulings are other support mechanisms that have been used with other power projects at the federal, state, and local levels.

Project definition documents also need to be developed early, including engineering technical documents and other documents that support the AFC. Key CCS activities include:

- Plant design basis
- System descriptions
- Projected performance (including heat and mass balances and power consumption)
- Air permitting details
- Water permit details
- Optimize trade off costs (value engineering)
- Public safety
- Noise
- Visual (artist rendition)
- Detailed cost estimate
- Final Level I schedule
- Geotechnical reports

Key stakeholders include those directly involved in the commercial agreements and project development and well as numerous others who support the project development and siting efforts, including:

- California Energy Commission
- National labs and the DOE
  - o Lawrence Livermore National Laboratory
  - o National Energy Technology Laboratory
- Researchers knowledgeable about the subject matter

- o CB&I
- o BKI
- Technology Suppliers
- Utility representatives
- Members of relevant technical society committees

# 6.2 Conclusions

Previous portions of this study have identified numerous CCS technologies that are potentially applicable to NGCC plants in California. While some of these technologies appear to be more suitable to the water constrained high temperature environment in California, pilot plant testing of a single technology would be of limited benefit. The course of testing support technologies, such as FGR and wet cooling would be of benefit regardless of the CCS eventually selected.

The effects of increased CO2 concentration in the flue gas, provided by FGR, and of lower CCS operating temperature, provided by wet cooling, would be highly dependent on the solvent used in the CCS, and the method of cooling the FGR stream. Therefore, the design of the pilot plant should include the following features:

- The ability to recirculate produced CO2 to vary the flue gas concentration from 4 percent to 10 percent.
- The ability to vary the temperature of the recirculated flue gas from 59°F to 130°F.
- The ability to vary CCS cooling water temperature from 70°F to 100°F.
- The ability to accommodate a number of different solvents.
- The ability to vary the CCS input flue gas flow and temperature to evaluate CO2 capture performance in response to power plant power output variations as a result of specific manual or automatic generation control variations.

To avoid site limitations, additional design features to reduce land dependency should also be considered, including:

- The ability to store and liquefy CO2 to enable the product to be transported for sequestration testing or industrial use.
- The ability to utilize an independent source of auxiliary power and steam to minimize the impact on an existing power plant or to support a completely independent site. This source could be in the form of a small CT and HRSG or one of the developmental one step generation and capture systems such as the Clean Energy Systems oxy-fuel system.

The results of these pilot plant tests are expected to provide the California power generation industry with technologies that can improve the performance of any CCS without being limited to vendor proprietary technologies.

CCS with FGR has virtually the same levelized COP as the Base Case with CCS at \$30/MWh incremental cost and \$85/ton avoided CO2. The hybrid and wet cooling cases show roughly the same levelized costs of production at \$30/MWh incremental cost and \$84-85/ton avoided CO2. Wet cooling is less expensive than hybrid cooling on a levelized COP basis, but the difference is quite minimal. Optimization of the FGR design has the potential to reduce the incremental levelized costs of production for all three of the FGR cases below that of the base case with CCS but without FGR.

The three parameters that have the largest sensitivity ranges are capacity factor, CCS equipment cost, and discount rate. The most economic cases will be dispatched as much as possible and thus have a higher capacity factor, will have the lowest CCS equipment costs and thus the lowest capital costs, and will have the most favorable financing and thus the lowest discount rate. In a very favorable technical, financial, and power market environment, if a project that utilized CCS with FGR and wet cooling was able to achieve a capacity factor of 90%, a CCS cost at 30 percent less than the base cost, and a discount rate of 3 percent, the incremental levelized COP for the CCS with FGR and wet cooling case could be as low as \$13/MWh and the levelized cost per CO2 avoided could be as low as \$37/ton. Optimization of the FGR system has the potential to reduce the costs even further.

# CHAPTER 7: Risks and Concerns

# 7.1 Carbon Capture Technology

The technology risks fall into three categories:

# 7.1.1 Research

Successful implementation of CCS on California NGCC power plants is dependent on the development of processes and/or solvents that will provide acceptable performance at the high CCS cooling temperatures encountered with dry cooling in California. Much of the research in these areas is government funded, posing the risk that this funding may be sharply reduced due to current economic conditions.

# 7.1.2 Scale Up

The most advanced of the carbon capture systems in development are the amine solvent based systems such as MEA. These systems have demonstrated acceptable operation on side stream flue gas at less than 100 MW equivalent size. Scaling up to full size systems capable of handling several hundred megawatts poses numerous challenges, including increasing the size of the absorber and desorber vessels or moving to multiple vessels. Using the experience of sulfur oxide scrubbers, it could take many years for the scale ups to be proven.

#### 7.1.3 Market

The current market for development of CCS technologies has been focused largely on coal fired plants. As environmental regulations governing coal plants become more stringent and as natural gas prices fall, many owners are choosing to shut down the units. New coal-fired power plants, based on EPA's proposed GHG New Source Performance Standards at the time this report was written would be required to install CCS, which in combination with low natural gas prices has dramatically reduced new coal fired power plant development. High efficiency NGCC operations is currently accepted nationally as CO2 best available control technology (BACT) as part of new source review (NSR) applications for new or modified NGCC facilities. Therefore, there is currently little demand for CCS for new NGCC units. If this trend continues, the market for CCS may shrink to the point where major vendors leave the market.

# 7.2 CO2 Pipeline Transportation and Storage

The risks of pipeline transportation of CO2 include the following:

- Backpressure or reversal of flow caused by failure of compression equipment.
- The need to isolate a segment of pipeline in the event of a leak.
- The need to depressurize a discreet segment of a pipeline.

Because CO2 within a pipeline is at very high pressures, a sudden pipeline failure could lead to a high velocity release of gases. The dense nature of CO2 also presents a potential safety hazard as a release of this gas will displace oxygen. As such, designers of CO2 pipelines take

precautions into consideration in the pipeline design basis. A sudden failure event should be taken into account as part of a risk analysis in the design, construction, operating, and monitoring of a CO2 pipeline.

The risks of long term geologic storage of CO2 are the following:

- Induced seismicity of CO2 injection operations.
- Injection well integrity.
- Subsurface distribution of the CO2 plume.
- Surficial evidence of CO2 escape and impact to groundwater quality.

It has been demonstrated that the injection of fluids into the subsurface can result in seismic events. Most of these induced seismic events are not documented as earthquakes, because they do not release enough energy to be felt at the surface. However, seismic risk is an important consideration in reservoir selection, and in the design, operation, and monitoring of CO2 storage. The identification and proximity to active faults is an important geologic criterion in reservoir selection. The installation of specialized seismic monitoring equipment will be required in the monitoring plan to minimize this risk.

The leakage of CO2 at the wellhead could occur around the cement seals. To minimize this leakage scenario a series of well integrity tests and geophysical logs will be performed during and after the installation of the injection and monitoring wells.

The leakage of CO2 from the storage reservoir could occur along the following pathways:

- Leakage from existing wells within the reservoir.
- Leakage along existing or induced fractures in the cap rock.
- Leakage along known faults.

To minimize these leakage scenarios the following actions will need to be conducted:

- A detailed geologic model will be conducted to determine the geographic and the stratigraphic zones that the CO2 will migrate into during the life time of the project including the post closure period.
- Based upon the identification of the zone, a detailed investigation of all potential
  existing wells that have been installed into the zone of the CO2 plume will be
  conducted.
- All of these well will be assessed to determine their construction characteristics and to determine if any well sealing operations will need to be conducted.
- Geotechnical analyses will be conducted on the cap rock to determine its strength characteristics such that the injection pressures inducted at the well head will not jeopardize their integrity.

- A detailed geologic and seismic investigation will be conducted to identify all known faults and to determine the potential for leakage along their fault zones.
- The selection of well locations within the wellfield will be adjusted to not allow the migration of the CO2 plume to encounter faults that could allow for the escape of CO2 during the life time of the project including the post closure period.
- A series of CO2 monitoring points will be established to document the migration of the subsurface CO2 plume.
- Data from these monitoring points will be used to modify the injection operations, if necessary, to minimize the potential for loss of CO2 into overlying fresh groundwater and the atmosphere.

Measurement techniques will be developed for the detection of CO2 leakage from a storage reservoir. The measurement techniques will addressed in a site monitoring plan for the CCS facility. The injection of CO2 for CCS will be conducted to ensure the protection of underground sources of drinking water and the atmosphere from injection related activities.

# 7.3 Economics

# 7.3.1 Capacity Factor

Fairly high capacity factors were assumed in the base case economics (65% for the retrofit case and 80% for the new build cases). If actual capacity factors are lower than the base case assumptions, the lifecycle economics will be negatively impacted, likely significantly. The economic dispatch in California is very sensitive to small changes in future natural gas prices and CO2 emissions allowance prices. In order to mitigate the risk of low economic dispatch, as a policy measure to encourage CCS, a must-run designation could be assigned to some of the first units with CCS, for at least some of the remaining life. Such a policy is expected to require funding to support operation of facilities at capacity factors that exceed their economic dispatch.

# 7.3.2 Financing

Financing directly impacts the discount rate, one of the most important parameters affecting the lifecycle economics. Financing a project that relies on technology with limited commercial experience can be difficult, particularly when relying on private project financing. Using private project financing, a risk premium will be applied to the equity rate of return and debt interest rate if the project is deemed to be more risky due to reliance on technology that has not been proven commercially. Such a risk premium would increase the discount rate and thus the lifecycle cost of power and cost of avoided CO2. The discount rate is also affected by the off take agreements that are in place. For example, having a power purchase agreement (PPA), CO2 sales agreement, or a dispatch guarantee would result in less risky revenue streams than a pure merchant market approach and would likely result in a lower discount rate. Financing a CCS retrofit for an existing plant could result in similar difficulties to financing a new plant with CCS. Additionally, for a retrofit plant with an existing PPA, the capacity derate from a retrofit CCS system could trigger substantial capacity penalties in the PPA. Government financing (either in full or in part) could reduce or eliminate the risk premium and improve the

lifecycle economics; however, such an arrangement would entail shifting project risks to the government or ratepayers.

# **CHAPTER 8:** Conclusions

# 8.1 CO2 Capture Technology

The CO2 capture approach least disruptive to an existing NGCC unit would be post-combustion CO2 capture. Although post-combustion CO2 capture cannot be considered proven at utility power plant scale, some capture processes have been demonstrated at large pilot or pre-commercial scale facilities and suppliers claim it is ready for full-scale application at NGCC power plants. However, special consideration must be given to the unique requirements at many California locations.

The Study indicated that the capture effectiveness and parasitic power consumption of the CO2 capture system will be significantly affected by the temperature of the cooling water available. Performance analyses conducted during the Study support the following conclusions:

- Chilling the CCS cooling water with refrigeration would improve the CO2 capture effectiveness but would increase the parasitic power load and increase the capital expenditures.
- Operating the CCS with cooling water temperatures achievable with a dry air cooler has the possibility of providing adequate capture effectiveness while reducing the parasitic power load. With this approach, regulatory flexibility to allow higher CO2 emissions during high temperature extremes may be necessary. This situation would change significantly for a plant with a source of reclaimed water, such as wastewater treatment plant effluent, or gray water, in sufficient quantities for the CCS cooling requirements.
- Information from CCS demonstration tests indicate that the CCS system is more effective with higher CO2 concentrations in the flue gas being treated. Preliminary studies have been performed for recirculation of a portion of the flue gas back to the CT inlet (known as FGR) to both increase the CO2 concentration and reduce the flue gas treatment flow. The net capacity reduction for a comparable new-build NGCC facility would be less, about 11 percent, because of greater opportunities to optimize the integration of the CO2 capture and compression systems into the plant design. Similarly, the use of steam and power in the process of capturing and compressing CO2 reduces the overall net efficiency of an NGCC power plant with CCS. Measured as an increase in net heat rate, this impact is about 17 percent for the retrofit case and about 12 percent for the new-build case.

Pre-combustion CO2 capture utilizes technologies developed in the chemical process industry for removal of carbon from natural gas fuel. Many of these technologies have been demonstrated at a utility scale for the cleanup of synthesis gas at coal gasification combined cycle plants. CTs have been developed and demonstrated that can burn coal synthesis gas consisting of hydrogen and carbon monoxide. Although some CT vendors have treated hydrogen combustors with diluents such as nitrogen, further development is needed to develop

a CT that operates efficiently and reliably on pure hydrogen from a pre-combustion CCS system. Thus, while the equipment needed for pre-combustion carbon capture is commercially available, this equipment has not yet been combined to demonstrate a utility power plant scale system.

In oxy-fuel combustion, removing the nitrogen fraction of combustion air greatly reduces the volume of combustion flue gas that must be treated for carbon capture. Cycles are under development that recycle a portion of the wet flue gas mixture or separate and recycle only the CO2 back to the combustor. While some demonstration tests have been run with small CTs and commercial oxygen plants, considerable development is needed to perfect the equipment sufficiently to support full scale commercial operations. In addition, there are challenges associated with the high cost and high auxiliary power requirements of the oxygen plant.

# 8.2 CO2 PipelineTransportation and Storage

The technical issues associated with CO2 compression and pipeline transport are well understood because CO2 has been used for over 40 years in EOR operations. Currently there are over 4,000 miles of CO2 pipeline in the Unites States.

The permitting, construction, and integrity of CO2 pipelines between a plant site and a geologic storage reservoir are not expected to be significant challenges to implementing CCS at most NGCC sites. The risks associated with CO2 transportation by pipeline can be mitigated through an awareness of the risks involved and implementation of suitable engineering controls.

California does not currently have a framework in place to address large volume CO2 pipeline permitting, design, and operation. CO2 pipeline safety currently is overseen by the State Fire Marshall. There are challenges as well as an opportunity for policymakers to draft appropriate statutes or regulations to assure safety, optimized routing, and which may include authorizing the use of eminent domain for CO2 pipeline right-of-ways.

The availability of geologic reservoirs with sufficient capacity the construction of injection and monitoring wells, and leakage and other risks, reviewed in Chapter 4, are not expected to be significant barriers to CCS implementation at most NGCC sites. However, there are certain regulatory, permitting, and legal issues that could hinder the efficient development of CO2 storage sites. These issues include site permitting of CO2 storage reservoirs, permitting of Class VI CO2 injection wells, ownership and use of the pore space in the reservoir, and long-term liability of CO2 storage, reviewed further in Chapter 1.

The estimated EPC costs for the CO2 transportation and injection systems for both the retrofit and new build scenarios evaluated in the Study were less than 5 percent of the total CCS EPC costs.

# 8.3 Economics

Table 27 summarizes the impact of implementing CCS on the net generating capability and net plant heat rate for both the retrofit and new build NGCC plants. The new build case benefits from optimization and integration of the CCS into the design of the new build NGCC facility, compared to the retrofit case.

Table 27: Summary of Key NGCC Performance Impacts Due to CCS

	Retrofit	New Build
Change in Net Generating Capability	-14.5%	-11.0%
Change in Net Plant Heat Rate	+16.7%	+12.1%

Source: CB&I

Table 28 summarizes the capital costs for implementing CCS for both the retrofit and new build cases. The total EPC includes the CO2 capture and compression system as well as the CO2 pipeline and injection systems. The total capital cost listed in Table 28 includes total EPC costs, Owner's costs, interest during construction, inflation and escalation, and project contingency.

Table 28: CCS Capital Cost Summary (\$ million) - 2012\$

	Retrofit	New Build
Total EPC Cost <sup>1</sup>	\$861	\$899
Total Capital Cost <sup>2</sup>	\$1,088	\$1,143

<sup>&</sup>lt;sup>1</sup> CO<sub>2</sub> capture, compression, pipeline and injection systems

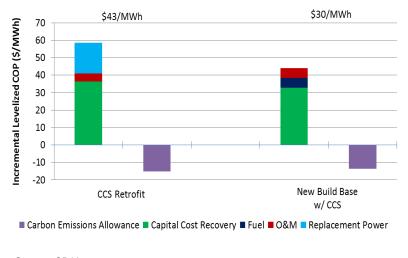
Source: CB&I

Factors which contribute to higher capital costs for CCS systems installed at California NGCC sites versus typical U.S. locations include more expensive dry cooling for the power plant and CCS system, and higher labor costs in California compared to other U.S. locations. The cost estimates in this Study assumed an EPC contracting structure instead of an engineering, procurement, construction management (EPCM) contracting structure, which monetizes more of the risk in the cost estimate.

Figures 24 and 25 compare the incremental levelized COP and the levelized cost per ton of CO2 avoided for the retrofit and new build scenarios. The retrofit cases do not benefit as much from optimization and integration of CCS into the design of the NGCC facility as for new build applications. In addition, the retrofit scenarios include the cost of replacement power due to the CCS derate on net generating capability. Both cases benefit from a reduction in the carbon emission allowance due to lower carbon emission levels. The levelized cost was determined based on a real discount rate of 5 percent.

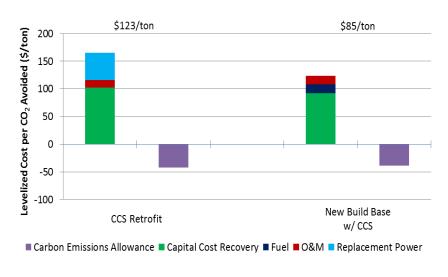
<sup>&</sup>lt;sup>2</sup> EPC costs, Owner's costs, interest during construction, inflation and escalation, and project contingency

Figure 24: Incremental Levelized COP for Retrofit and New Build NGCC



Source: CB&I

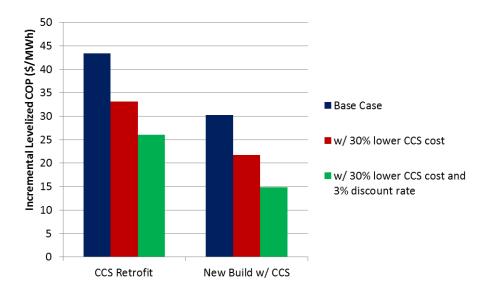
Figure 25: Levelized Cost per ton of CO2 Avoided



Source: CB&I

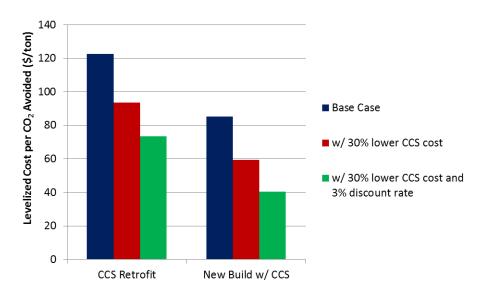
Figures 26 and 27 illustrate the impact on incremental levelized COP and levelized cost per ton of CO2 removed under two optimistic scenarios, assuming lower future capital costs and 2 percent lower discount rate. Factors which could contribute to lower future capital costs include receipt of government funded grants, breakthroughs in technology, improvements in plant design ("learn by doing"), and use of reclaimed water instead of dry cooling. Obtaining detailed vendor pricing information and additional site-specific information than what was available in this Study may also result in lower capital cost estimates. Lower discount rates would likely require government subsidies such as loan guarantees. However, such an arrangement would entail shifting project risks to the government or ratepayers.

Figure 26: Incremental Levelized COP for Retrofit and New Build NGCC



Source: CB&I

Figure 27: Levelized Cost per ton of CO2 Avoided



Source: CB&I

# CHAPTER 9: Recommendations

# 9.1 Technology

There are many CO2 capture technologies available and under development. Development specifically targeted to California NGCC power plants is needed, as follows:

- Follow and support, if appropriate, the development of capture solvents and advanced technologies to improve the functionality of carbon capture at high ambient temperatures.
- Develop CO2 capture process simulation models. Such models could simulate unique
  aspects of applying post- combustion CO2 capture at specific California power plant
  sites and could prove useful in screening solvents for future pilot plant evaluations. The
  models could also serve as a useful post-pilot plant tool for optimizing post-combustion
  solvent-based CO2 capture systems for application at various locations in California.
- Consider facilitating private/public investment in a pilot project to evaluate capture
  technologies tailored specifically to California design conditions would be the basis for
  award of the grant or study money. The pilot plant facility could also test technology
  improvements such as FGR and high temperature solvents and would assist in
  establishing the performance and cost basis needed to facilitate commercialization. A
  pilot plant Project Charter, as described in Chapter 3, may be a guide in developing the
  pilot facility.
- Follow and support, if appropriate, the development of CT-based oxy-fuel combustion systems and pre-combustion carbon capture systems to assist scale-up to commercial size. These technology options, with longer commercialization timelines than post-combustion capture technologies, and potentially limited application as retrofit systems, may present opportunities for new build NGCC plants at some point in the future.
- Follow technology developments related to natural gas CCS. Examples include the Technology Centre Mongstad (TCM), which was commissioned in May, 2012 and the Peterhead Project in Aberdeenshire, Scotland. The TCM facility is unique in that it can test exhaust gases from two nearby sources a 280-megawatt natural gas combined heat and power (CHP) plant and the Mongstad refinery. The CHP flue gas has a CO2 content of about 3.5 percent, representative of NGCC flue gas. The TCM is the largest test facility in the world. The TCM issued a Request for Interest for use of the existing test facilities by interested parties.
- The Peterhead Project in Aberdeenshire, Scotland was selected as a preferred bidder in the UK's £1 billion (\$1.52 billion) CCS demonstration competition. The Peterhead Project involves capturing around 90 percent of the CO2 emissions from an existing NGCC plant and transporting it and storing it in a depleted gas field beneath the North

Sea. This project, should it move forward, could represent the world's first full-scale CCS installation on a NGCC facility.

# 9.2 Economics Incentives

In the current market and regulatory environment, the projected lifecycle costs for an NGCC plant with CCS will exceed current market costs using currently available technology. A variety of different types of incentives could improve economics of early CCS projects in California Potential options include:

- RD&D funding for CCS development from a combination of stakeholders (e.g. state and federal government, private industry, shareholders and ratepayers).
- Early mover CCS incentive programs similar to those proposed in previous federal climate change bills (including cash payments per ton of CO2 sequestered and possibly direct funding).
- Tax incentives for sequestering anthropogenic sources of CO2 for EOR (e.g., policy in Texas), and must-run designation in power markets.
- Capital cost subsidies, including federal (e.g., DOE cost share grants), and state subsidies (potentially through cap and trade auction proceeds or an electric utility surcharge across all utilities and ratepayers), or loan guarantees (similar to DOE loan guarantees).
- Formal recognition of CO2 sequestered by CCS projects in the cap and trade program.
- Prizes such as the President's upcoming Fiscal Year 2014 budget request that would
  establish a new \$25 million prize for the first NGCC plant to integrate CCS technology.
  It remains to be seen if this level of support will stimulate commercial activity.
  Nevertheless, California should monitor the developments with this proposed Federal
  support of CCS for NGCC plants and determine if opportunities for participation by
  California present themselves going forward.

# **GLOSSARY**

# Abbreviations, Acronyms and Chemical Symbols

The following is a list of definitions for the abbreviations, acronyms and chemical symbols, financial terms, technical terms, and units of measure used in this report.

Term	Definition
\$/MWh	Dollars Per Megawatt-Hour
2x2x1	2-CTs, 2-HRSGs and 1-ST
\$/kW	Dollars Per Kilowatt
AEO	Annual Energy Outlook
AFC	Application For Certification
Ar	Argon
ASU	Air Separation Unit
BACT	Best Available Control Technology
BTU	British Thermal Unit
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCS	Carbon Capture and Storage
CEQA	California Environmental Quality Act
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO <sub>2</sub>	Carbon Dioxide
COC	Conditions of Certification
СОР	Cost of Production
CPUC	California Public Utilities Commission
CPV	Competitive Power Ventures
СТ	Combustion Turbine (Gas Turbine)
СТБ	Combustion Turbine Generator

DOE	Department of Energy
DOGGR	Department of Oil, Gas and Geothermal Resources
DOT	Department of Transportation
EGR	Enhanced Gas Recovery
EGREGI	Exhaust Gas Recirculation Injection
EIA	Energy Information Administration
EIR	Environmental Impact Report
Energy Commission	California Energy Commission
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPCM	Engineering, Procurement and Construction Management
EPRI	Electric Power Research Institute
FGR	Flue Gas Recirculation
GHG	Green House Gas
GPM	Gallons Per Minute
GTG	CT Generator
H2, H <sub>2</sub>	Hydrogen
H <sub>2</sub> O	Water (moisture)
HAP	Hazardous Air Pollutant
HHV	High Heating Value
HRSG	Heat Recovery Steam Generator
IOU	Investor Owned Utility
IP-LP	Intermediate pressure to low pressure
IRS	Internal Revenue Service
kg	kilogram
K-T	Kepner-Tregoe
kWh	Kilowatt-hour

LHV	Low Heating Value
LLNL	Lawrence Livermore National Laboratory
LOR&S	Laws, Ordinances, Regulations & Standards
MACRS	Modified Accelerated Cost Recovery System
MEA	Monoethanolamine
MRV	Monitoring, Reporting and Verification
MW	Megawatt
N <sub>2</sub>	Nitrogen
ND	Negative Declaration
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NH <sub>3</sub>	Ammonia
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NSR	New Source Review
O&M	Operations and Maintenance
O <sub>2</sub>	Oxygen
PAC	Project Advisory Committee
Panel	CCS Review Panel
PC	Pulverized Coal
PDF	Portable Document Format
PEACE	Plant Engineering and Cost Estimate
PFD	Process Flow Diagram
PHMSA	Pipeline and Hazardous Materials Safety Administration
PLC	Programmable Logic Control
POU	Public Owned Utility
PPA	Power Purchase Agreement
ppmvd	Parts Per Million Volume Density

ppmvw	Parts Per Million Volume Weight
R&D	Research and Development
RD&D	Research, Development, and Demonstration
REG	Regenerator (in Chilled Ammonia Process)
RFI	Request for Information
RFP	Request for Proposal
ROW	Right of Way
SCR	Selective Catalytic Reduction
SOx	Sulfur Oxides
ST	Steam Turbine
TCM	Technology Centre Mongstad
UIC	Underground Injection Control
US DOE	United States Department of Energy
US EPA	United States Environmental Protection Agency
USDW	Underground Sources of Drinking Water
WB	Wet Bulb
WECC	Western Electricity Coordinating Council (US)
WESTCARB	West Coast Regional Carbon Sequestration Partnership

# Terms Used in the Lifecycle Cost Model

# Ancillary Service Revenue:

Revenue that a plant earns by providing ancillary services to support the reliable operation of the transmission system.

# Carbon Penalty/CO2 Emissions Penalty:

The cost of emitting CO2 due to CO2 emissions taxes; cap and trade CO2 emission markets; or other regulatory mechanisms.

# Construction Cash Flow Midpoint:

The point during construction where half the construction costs have been spent, expressed as a number between 0 and 1 with 0 representing the beginning of construction and 1 the end; used to approximate the interest during construction.

#### **Construction Interest:**

The interest on project capital costs accumulated during construction.

### Construction Period:

Length of time between the beginning of construction to the point of commercial operation (used in the levelized cost model to calculate interest during construction).

#### Construction Interest Rate:

The interest rate used to calculate the interest on project capital costs accumulated during construction.

#### Discount Rate:

The rate in which future cash flows are discounted to the present in order to account for the time value of money; the weighted average cost of capital is often used to determine the discount rate.

#### **Economic Life:**

The period over which the project economics are to be evaluated, which often equals the amortization period.

#### Effective Tax Rate:

The combined tax rate (typically includes federal and state tax rates) that is used to determine the levelized annual capital recovery rate.

#### Engineering, Procurement and Construction (EPC) Cost:

The Engineering, Procurement and Construction (EPC) cost used in the study is for the base power plant carbon capture system and CO2 transportation and injection system.

#### Electricity Value:

The value of replacement electricity (e.g., replacement power purchase cost, additional capacity cost or new generation cost or loss of revenue from reduced generation).

#### Federal Tax Rate:

The federal corporate income tax rate.

# Fixed Operation and Maintenance Costs:

The annual cost to produce electricity that does not vary depending on the amount of electricity production. The study differentiates the fixed operation and maintenance cost for the carbon capture system and CO2 transportation and injection system.

#### General Inflation:

The percentage that the cost of general goods and services increase per year (related to the availability of money and credit).

#### **Incremental First Year Cost:**

Costs in the first year of operation after the retrofit is completed minus the costs that would have been incurred if the retrofit did not take place.

#### **Incremental Levelized Cost:**

Levelized costs of the project after the retrofit has been completed minus the levelized costs that would have been incurred if the retrofit did not take place.

## Levelized Capital Cost Recovery:

The fixed annual capital cost that is charged based on the levelized capital cost recovery rate.

#### Levelized Capital Recovery Rate:

The fixed annual percentage of the total capital cost that must be charged over the economic life of the project in order for this cash flow to have an equivalent net present value (NPV) to the capital debt and equity financing cash flows including adjustments for taxes and depreciation.

### Levelized Cost of Production:

The price per unit of production that must be charged over the life of the project in order for the net present value of the project cash flows (including both the revenues and costs) to equal zero.

#### Levelized CO2 Removal Cost:

The total cost of building and operating the CO2 removal and compression system over the remaining plant economic life, converted to equal annual payments such that the NPV of the annual payments equals the NPV of the costs.

### Lifetime Average Availability:

Average percent of time during the life of the plant that the plant is available to operate.

### Lifetime Average Capacity Factor:

Average percentage of time during the life of the plant that the plant is operating at full load (or full load equivalent).

#### Net Present Value (NPV):

The sum of the future cash flows of a project, discounted at the discount rate, minus the initial project investment.

#### Nominal Escalation Rate:

The percentage that the cost of specific goods or services increases per year (includes general inflation and real escalation).

#### Owner's Cost:

Capital cost in addition to the EPC cost that the owner is typically responsible for, such as project development, royalties, permits and licenses, operating spares, project oversight, etc.

#### Pre-Retrofit:

Refers to costs based on existing unit generation capability before retrofit of the CO2 capture system.

## **Project Contingency:**

Additional cost added to the project capital cost estimate to account for unexpected costs incurred during construction that were not included in the EPC contract or in the Owners Cost.

#### Real Escalation Rate:

The percentage that the cost of specific goods or services increase per year excluding the effects of general inflation (due to changing technology or policy or the availability of materials, labor, or other commodities).

#### Reference Year:

The year in which the initial costs and prices are based.

#### State Tax Rate:

The state corporate income tax rate.

#### Variable Operation and Maintenance Costs:

The annual cost to produce electricity that varies depending on the amount of electricity production. The study differentiates the variable operation and maintenance cost for the carbon capture system and CO2 transportation and injection system.

### Year Retrofit in Operation:

The year in which the plant is expected to resume operation after the carbon capture retrofit is completed.

### **Geologic / Sequestration Terms**

### Active Fault (Alquist –Priolo):

A fault that had surface displacement within Holocene time (about the last 11,000 years).

#### Anticline:

A fold, generally convex upward, whose core contains the stratigraphically older rocks. Applied to strata that dip in opposite directions from a common ridge or axis.

## Casing:

Steel pipe cemented in place during the construction process to stabilize the wellbore. The casing forms a major structural component of the wellbore and serves several important functions: preventing the formation wall from caving into the wellbore, isolating the different formations to prevent the flow or cross flow of formation fluid, and providing a means of maintaining control of formation fluids and pressure as the well is drilled. The casing string provides a means of securing surface pressure control equipment and down hole production equipment, such as the drilling blowout preventer (BOP) or production packer. Casing is available in a range of sizes and material grades.

#### Contour:

An imaginary line, or a line on a map or chart, that connects points of equal value, e.g., elevation of the land surface above or below some reference value or datum plane, generally sea level. Contours are commonly used to depict topographic or structural surfaces; they can also readily show the laterally variable properties of sediments or any other phenomenon that can be quantified.

#### Fault:

Surface of rock rupture along which has been differential movement.

#### Fault-Normal:

A fault in which hanging wall appears to have moved downward relative to footwall; opposite of thrust fault. Also called gravity fault.

#### Fault-Reverse:

A fault in which the hanging wall appears to have moved upward relative to footwall; also called thrust fault. A fault on which the hanging wall appears to have moved upward relative to the footwall. The dip of the fault is usually greater than 45 degrees. There is dip separation but there may or may not be dip slip.

### Fault-Strike Slip:

A fault with a component of movement or slip that is parallel to the strike of the fault, with horizontal displacement or horizontal separation.

#### Field:

An accumulation, pool, or group of pools of hydrocarbons or other mineral resources in the subsurface. A hydrocarbon field consists of a reservoir in a shape that will trap hydrocarbons and that is covered by an impermeable, sealing rock. Typically, the term

implies an economic size: commonly distinguished by the predominance of a particular resource (e.g. oil or gas).

#### Formation:

A body of sedimentary rock identified by lithic characteristics and stratigraphic position; it is prevailing but not necessarily tabular, and is map able at the Earth's surface or traceable in the subsurface. The formation is the fundamental unit in lithostratigraphic classification. A general term applied by drillers to a sedimentary rock that can be described by certain drilling or reservoir characteristics; e.g. hard formation, cherty formation, or porous formation.

#### Formation Pressure:

The pressure of fluids within the pores of a reservoir, normally hydrostatic pressure, or the pressure exerted by a column of water from the formation's depth to sea level.

# Injection Well:

An injection well is drilled for the safe disposal of fluids, the hydraulic control or other purpose. Injection wells have been an integral part of California's oil and gas operations for over 50 years. Currently, over 25,000 oilfield injection wells are operating in the state. Injection wells are used to increase oil recovery and to safely dispose of the salt and fresh water produced with oil and natural gas.

Injection wells are classified by the U.S. Environmental Protection Agency (USEPA) into six classes according to the type of fluid they inject and where the fluid is injected, as follows:

- Class I wells inject hazardous and non-hazardous wastes below the lowermost underground source of drinking water (USDW). Injection occurs into deep, isolated rock formations that are separated from the lowermost USDW by layers of impermeable clay and rock.
- Class II wells inject fluids associated with oil and natural gas production operations. Most of the injected fluid is brine that is produced when oil and gas are extracted from the earth.
- Class III wells inject super-heated steam, water, or other fluids into formations
  to extract minerals. The injected fluids are then pumped to the surface and the
  minerals in solution are extracted. Generally, the fluid is treated and re-injected
  into the same formation.
- Class IV wells inject hazardous or radioactive wastes into underground sources
  of drinking water. These wells are banned under the Underground Injection
  Control (UIC) program because they directly threaten public health.
- Class V wells are injection wells that are not included in the other 4 classes.
   Some Class V wells are wastewater disposal wells used by the geothermal industry, but most are wells such as septic systems and cesspools. Generally,

they are shallow and depend upon gravity to drain or "inject" liquid waste into the ground.

 Class VI wells - inject (CO2) into deep underground subsurface rock formations for long-term storage, or geologic sequestration. The Division does not have primacy to regulate Class VI wells. Class VI wells are permitted and regulated though the US EPA.

In California, all Class II injection wells are regulated by the Department of Conservation, Division of Oil, Gas, and Geothermal Resources, under provisions of the state Public Resources Code and the federal Safe Drinking Water Act.

# Monitoring Well:

A well installed within a zone of interest to monitor specific properties of the formation. The properties may include, but are not limited to, gas pressure and content, water level, and chemical properties. The monitoring well must be installed in a manner that isolates the particular horizon from the surrounding formation and the ambient surface environment but must also provide unrestricted access to the monitored zone.

# Porosity:

The amount of void space in a reservoir usually expressed as percent voids per bulk volume. Absolute porosity refers to the total amount of pore space in a reservoir, regardless of whether or not that space is accessible to fluid penetration. Effective porosity refers to the amount of connected pore spaces; i.e., the space available to fluid penetration.

### Permeability:

The permeability of rock is its capacity for transmitting a fluid. Degree of permeability depends upon the size and shape of the pores, the size and shape of their interconnections, and the extent of the latter. It is measured by the rate at which a fluid of standard viscosity can move a given distance through a given interval of time. The unit of permeability is the darcy. See also: millidarcy; coefficient of permeability.

# Reservoir Rock:

A permeable rock containing oil or gas. A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. Sedimentary rocks are the most common reservoir rocks because they have more porosity than most igneous and metamorphic rocks and form under temperature conditions at which hydrocarbons can be preserved. A reservoir is a critical component of a complete petroleum system.

# Strike:

Direction of line formed by intersection of a rock surface with a horizontal plane. Strike is always perpendicular to direction of dip. The course or bearing of the outcrop of an inclined bed, vein, or fault plane on a level surface; the direction of a horizontal line perpendicular to the direction of the dip.

# Trap:

A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate. Traps are described as structural traps (in deformed strata such as folds and faults) or stratigraphic traps (in areas where rock types change, such as unconformities, pinch-outs and reefs).

#### **Technical Terms**

#### Amine:

Any of a group of organic compounds of nitrogen that may be regarded as ammonia derivatives in which one or more hydrogen atoms has been replaced by a hydrocarbon radical.

#### Ammonia:

A compound of nitrogen and hydrogen with the formula NH3.

## British thermal unit (BTU):

Measure of energy, commonly used for thermal energy.

#### CO<sub>2</sub> Emissions:

Amount of CO2 emissions that the plant emits when operating at full load.

#### CO2 Emissions Avoided:

The amount of CO2 captured onsite when the plant is operating at full load minus the CO2 emission from a new associated power replacement facility.

#### CO2 Emissions Removed:

The amount of CO2 emissions that are captured onsite when the plant is operating at full load (does not include any CO2 capture associated with replacement power).

## Gross Electricity Output:

The output at the turbine generator terminals.

### Higher Heating Value (HHV):

Quantity of heat released by a unit amount of fuel once it is completely combusted at stoichiometric conditions and constant pressure and the products have returned to the initial temperature with any water vapor produced being condensed.

## Lower Heating Value (LHV):

Quantity of heat released by a unit amount of fuel once it is completely combusted at stoichiometric conditions and constant pressure and the products have returned to the initial temperature without any water vapor produced being condensed.

# Monoethanolamine (MEA):

(CH2)2OHNH2 an organic chemical compound that is both a primary amine (due to an amino group in its molecule) and a primary alcohol (due to a hydroxyl group in its molecule).

## Net Electricity Output:

Gross electricity output minus the average plant auxiliary, other internal plant loads and transformer losses measured at the high side of the transformer.

## Net Heat Rate (HHV, ISO):

The amount of fuel energy input in higher heating value (HHV) divided by net electric power output; ISO refers to conditions of 59°F sea level and 60% relative humidity.

#### Reference Plant:

A Reference Plant model approach was approved at the first Project Advisory Committee (PAC) meeting. In lieu of having specific California operating or in construction power plant data, industry standard values will be presented to show progress and the specific plant data factored in to the final deliverable it is available in time to support draft deliverables.

## Sequestration:

CO2 storage in underground geotechnical formations

### Storage:

CO2 storage in man-made facilities

#### **Units of Measure**

# System of Measurement:

The system of measurement used throughout this report is based on the US Customary System of Measures. The abbreviations of the units of measure used in this report are defined as follows:

## Concentration:

- ppm parts per million
- ppmvd parts per million volume dry
- ppmvw parts per million volume wet

#### Density:

- lb/cu ft pounds per cubic foot
- lb/gal pounds per gallon

# Energy

• Btu - British Thermal Unit

### Flow Rate:

- scfm standard cubic feet per minute
- acfm actual cubic feet per minute
- gpm gallons per minute
- gph gallons per hour
- kLb/Hr thousand pounds per hour

## Mass:

- lbs pounds
- tons tons (2000 lbs)

### Power:

- MWg megawatts gross
- MWn megawatts net
- kW kilowatt
- kVA kilo-volt-amp
- V volt
- A amp
- PF power factor

### Pressure:

- mPa mega Pascal absolute (145 pounds per square inch absolute)
- psi pounds per square inch
- psia pounds per square inch absolute
- psig pounds per square inch gauge

# Temperature:

- °C degrees Celsius (Centegrade)
- °F degrees Fahrenheit
- °R degrees Rankine

# Velocity:

- fpm feet per minute
- fps feet per second

# MKS:

• References are sometimes used

# **Agencies and Organizations**

See the Acknowledgements section for additional agencies and organizations.

The Shaw Group (Shaw) – Also known as Shaw Stone & Webster, Inc., was acquired by CB&I on February 13, 2013.

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A4	CB&I, Comparison of Cost and Performance Impacts
A5	CB&I, Regulatory and Permitting Issues of NGCC Facilities for CO <sub>2</sub> Capture and Injection Operations
A6	CB&I, Retrofit Options Analysis Procedure
A7	CB&I, New Build Options Analysis Procedure
A8	CB&I, Select Sites for Engineering Options Analysis
A9	CB&I, Retrofit Options Analysis Application / Sensitivity Analyses for Selected Retrofit Cases
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